SOUTHERN CO

FORM 10-K
(Annual Report)

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Address	30 IVAN ALLEN JR. BLVD., N.W. ATLANTA, GA 30308
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Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2011

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

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Securities registered pursuant to Section 12(b) of the Act: [1]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class		Registrant
Common Stock, $5 par value		**The Southern Company**
Class A preferred, cumulative, $25 stated capital		**Alabama Power Company**
5.20% Series	5.83% Series	
5.30% Series		
Senior Notes		
5.875% Series 2007B		
Class A Preferred Stock, non-cumulative, Par value $25 per share		**Georgia Power Company**
6 1/8% Series		
Senior Notes		
6.375% Series 2007D		
8.20% Series 2008C		
Senior Notes		**Gulf Power Company**
5.25% Series H		
5.75% Series 2011A		
Senior Notes		**Mississippi Power Company**
5 5/8% Series E		
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value		
5.25% Series		

Securities registered pursuant to Section 12(g) of the Act: [1]

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Preferred stock, cumulative, $100 par value			**Mississippi Power Company**
4.40% Series	4.60% Series		
4.72% Series			

1 As of December 31, 2011.

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Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	X	
Alabama Power Company	X	
Georgia Power Company	X	
Gulf Power Company		X
Mississippi Power Company		X
Southern Power Company		X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒ (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒ (Response applicable to all registrants.)

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Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2011: $34.6 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2012
The Southern Company	Par Value $5 Per Share	866,573,913
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	4,542,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2012 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2012 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b), (c), and (d) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	Meaning
2010 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2011 through 2013
Alabama Power	Alabama Power Company
Clean Air Act	Clean Air Act Amendments of 1990
Code	Internal Revenue Code of 1986, as amended
CPCN	Certificate of Public Convenience and Necessity
Dalton	Dalton Utilities
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
FP&L	Florida Power & Light Company
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Hampton	City of Hampton, Georgia
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated Coal Gasification Combined Cycle
IIC	Intercompany Interchange Contract
IPP	Independent Power Producer
IRP	Integrated Resource Plan
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MEAG Power	Municipal Electric Authority of Georgia
Mississippi Power	Mississippi Power Company
MW	Megawatt
NRC	Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative (formerly, Alabama Electric Cooperative, Inc.)
PPA	Power Purchase Agreement

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DEFINITIONS
(continued)

Term	**Meaning**
Progress Energy Florida	Florida Power Corporation, d/b/a Progress Energy Florida, Inc.
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power
RUS	Rural Utilities Service (formerly Rural Electrification Administration)
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
SRE	Southern Renewable Energy, Inc.
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, future earnings, dividend payout ratios, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expects,” “plans,” “anticipates,” “believes,” “estimates,” “projects,” “predicts,” “potential,” or “continue” or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company’s subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of Southern Company’s employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals, potential DOE loan guarantees, the SMEPA purchase decision, and utilization of investment tax credits;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on Southern Company’s business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company’s and its subsidiaries’ credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

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PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is domesticated under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930 and was admitted to do business in Alabama on September 15, 1948.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924 and was admitted to do business in Mississippi on December 23, 1924 and in Alabama on December 7, 1962.

In addition, Southern Company owns all of the common stock of Southern Power, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, in the State of North Carolina on February 19, 2007, in the State of South Carolina on March 31, 2009, in the State of Texas on October 26, 2009, and in the State of New Mexico on February 11, 2010.

Southern Company also owns all of the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power’s and Georgia Power’s nuclear plants and is currently developing new nuclear generation at Plant Vogtle, which is co-owned by Georgia Power. SCS is the system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary primarily for Southern Company’s investments in leveraged leases.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 KWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO’s capacity and energy. Alabama Power acts as SEGCO’s agent in the operation of SEGCO’s units and furnishes coal to SEGCO as fuel for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

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Southern Company's segment information is included in Note 12 to the financial statements of Southern Company in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Operating Companies

The traditional operating companies own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Traditional Operating Companies and Southern Power" herein.

Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into from time to time for reasons related to reliability or economics. Additionally, the traditional operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and Tennessee Valley Authority and with Carolina Power & Light Company (d/b/a Progress Energy Carolinas, Inc.), Duke Energy Corporation, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional operating companies have joined with other utilities in the Southeast (including some of those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional operating companies are represented on the National Electric Reliability Council.

The utility assets of the traditional operating companies and certain utility assets of Southern Power are operated as a single integrated electric system, or power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional operating companies and Southern Power. The fundamental purpose of the power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional operating company and Southern Power retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the power pool for use in serving customers of other traditional operating companies or Southern Power or for sale by the power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from power pool transactions with third parties.

Southern Company, each traditional operating company, Southern Power, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Southern Power and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power, which are subject to FERC regulations, in compliance with such regulations.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate Plant Farley and Plants Hatch and Vogtle, respectively. In addition, Georgia Power has a contract with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation – Nuclear Regulation" herein for additional information.

Southern Power

Southern Power is an electric wholesale generation subsidiary with market-based rate authority from the FERC. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based prices in the wholesale market. Southern Power's business activities are not subject to traditional state regulation like the traditional operating companies but are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

Southern Power is constructing a 720 MW electric generating plant in Cleveland County, North Carolina. This new plant is expected to go into commercial operation in December 2012. The total estimated construction cost is expected to be between $335 million and $365 million.

Southern Power is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste and is expected to begin commercial operation in June 2012. The total estimated cost of the project is expected to be between $470 million and $490 million.

On March 15, 2011, Southern Company transferred its ownership in its wholly-owned subsidiary, SRE, to Southern Power. SRE was formed in January 2010 to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. In March 2010, SRE and Turner Renewable Energy, Inc., through a subsidiary, entered into an engineering, construction, and procurement agreement with First Solar, Inc. for Plant Cimarron, a 30 MW solar photovoltaic plant near Cimarron, New Mexico, and assumed the associated PPA. In November 2010, Plant Cimarron began commercial operation. The transfer of net assets was accounted for by Southern Power as a transfer of net assets among entities under common control; therefore, the assets and liabilities of SRE were transferred from Southern Company to Southern Power at historical cost. The consolidated financial statements of Southern Power have been revised to include the financial condition and the results of operations of SRE since its inception in January 2010.

As of December 31, 2011, Southern Power had 7,908 MWs of nameplate capacity in commercial operation.

Other Businesses

Southern Holdings is an intermediate holding subsidiary primarily for Southern Company's investments in leveraged leases.

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets its services to non-affiliates within the Southeast. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. SouthernLINC Wireless also provides wholesale fiber optic solutions to telecommunication providers in the Southeast under the name Southern Telecom.

These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

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Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2012 through 2014, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" and Note 7 to the financial statements of Southern Company and each traditional operating company under "Construction Program" and Note 7 to the financial statements of Southern Power under "Expansion Program" in Item 8 herein. The Southern Company system's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. In 2012, the base level capital investment and capital expenditures are expected to be apportioned approximately as follows:

	Southern Company system *	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
New Generation	$2,325	$1	$861	$0	$1,335	$128
Environmental **	425	22	237	200	87	—
Transmission & Distribution Growth	550	160	337	40	13	—
Maintenance (Generation, Transmission, and Distribution)	1,233	488	532	147	52	—
Long-Term Service Agreements Capital	126	47	51	—	—	28
Nuclear fuel	333	135	198	—	—	—
General plant	275	84	87	15	9	31
Total	$5,267	$937	$2,303	$402	$1,496	$187

* These amounts include the amounts for the traditional operating companies and Southern Power (as detailed in the table above) as well as the amounts for the other subsidiaries. See "Other Businesses" herein for additional information.

** The 2012 base level capital investments for Georgia Power, Gulf Power, and Mississippi Power include certain environmental compliance investments associated with the EPA's Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule). The 2012 base level capital investment for Alabama Power does not include potential incremental environmental compliance investments associated with complying with the MATS rule. The Southern Company system is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. The potential incremental environmental compliance investments in 2012, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are as follows:

	Southern Company system	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**
		(in millions)			
MATS rule	Up to $370	Up to $170	—	Up to $45	Up to $30
Proposed water and coal combustion byproducts rules	Up to $40	Up to $5	Up to $30	Up to $5	Up to $1
Total potential incremental environmental compliance investments	Up to $410	Up to $175	Up to $30	Up to $50	Up to $31

For Southern Power, any incremental investments to comply with existing statutes and regulations, the MATS rule, or anticipated new environmental regulations in 2012 are expected to be immaterial.

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The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

See “Regulation – Environmental Statutes and Regulations” herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – “Jointly-Owned Facilities” in Item 2 herein for additional information concerning Alabama Power’s, Georgia Power’s, and Southern Power’s joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

See each of the registrant’s MANAGEMENT’S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

Fuel Supply

The traditional operating companies’ and SEGCO’s supply of electricity is derived mainly from coal. Southern Power’s supply of electricity is primarily fueled by natural gas. See MANAGEMENT’S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – “Electricity Business – Fuel and Purchased Power Expenses” of Southern Company and MANAGEMENT’S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – “Fuel and Purchased Power Expenses” of each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net kilowatt-hour generated for the years 2009 through 2011.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2012. These agreements have terms ranging between one and eight years. In 2011, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.80% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Clean Air Interstate Rule (CAIR) under the Clean Air Act. In 2011, the Southern Company system purchased approximately 563 tons of sulfur dioxide allowances and 3,096 tons of seasonal nitrogen oxide emission allowances to be used in current and future periods. As additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies’ fuel mix will be monitored to ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT’S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – “Environmental Matters” of Southern Company and each traditional operating company in Item 7 herein for information on the Clean Air Act, the MATS rule, the Cross State Air Pollution Rule (CSAPR), CAIR, the proposed water and coal combustion byproducts rules, and global climate issues.

SCS, acting on behalf of the traditional operating companies and Southern Power, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2012, SCS has contracted for 378 billion cubic feet of natural gas supply under agreements with remaining terms up to nine years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes that these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system’s natural gas generating units.

Changes in fuel prices to the traditional operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See “Rate Matters – Rate Structure and Cost Recovery Plans” herein for additional information. Southern Power’s PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems which obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. The territory has an area of approximately 120,000 square miles and an estimated population of approximately 16 million. Southern Power sells electricity at market-based prices in the wholesale market primarily to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

Alabama Power is engaged, within the State of Alabama, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 15 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to Alabama Municipal Electric Authority, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances.

Georgia Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within the State of Georgia, at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale currently to OPC, MEAG Power, Dalton, Hampton, various electric membership corporations, and non-affiliated utilities.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity, at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility and a municipality.

Mississippi Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to KWH sales by customer classification for the traditional operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. There are 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

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One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. PowerSouth owns generating units with approximately 2,027 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service territory. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service territory and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided, including the furnishing of protective capacity by Mississippi Power to SMEPA. In July 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase an undivided 17.5% interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In December 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

There are also 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

Forty-eight municipally-owned electric distribution systems and one county-owned system receive their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. In addition, Georgia Power serves the full requirements of Hampton's electric distribution system under a market-based contract. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power has PPAs with some of the traditional operating companies and with other investor-owned utilities, IPPs, municipalities, electric cooperatives, and an energy marketing firm. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional operating companies, also has a contract with SEPA providing for the use of the traditional operating companies' facilities at government expense to deliver to certain cooperatives and

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municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain United States government hydroelectric projects.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued “Grandfather Certificates” of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a “Grandfather Certificate,” the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate which are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Competition

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Policy Act of 1992 which allowed IPPs to access a utility’s transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice.

Generally, the traditional operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees as the result of self-generation (as described below) by customers and other factors.

Southern Power competes with investor owned utilities, IPPs, and others for wholesale energy sales primarily in the Southeastern U.S. wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power’s success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power’s plants, availability of transmission to serve the demand, price, and Southern Power’s ability to contain costs.

Alabama Power currently has cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess generation of such companies. During 2011, Alabama Power purchased approximately 115 million KWHs from such companies at a cost of $5 million.

Georgia Power currently has contracts in effect with 10 small power producers whereby Georgia Power purchases their excess generation. During 2011, Georgia Power purchased 18 million KWHs from such companies at a cost of $0.6 million. Georgia Power also has PPAs for electricity with two cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2011, Georgia Power purchased 261 million KWHs at a cost of $26 million from these facilities.

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Also during 2011, Georgia Power purchased energy from eight customer-owned generating facilities. Seven of the eight customers provide only energy to Georgia Power. These seven customers make no capacity commitment and are not dispatched by Georgia Power. Georgia Power does have a contract with the remaining customer for eight MWs of dispatchable capacity and energy. During 2011, Georgia Power purchased a total of 37 million KWHs from the eight customers at a cost of approximately $1 million.

Gulf Power currently has agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2011, Gulf Power purchased 240 million KWHs from such companies for approximately $11 million.

Mississippi Power currently has a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2011, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks during the summer months, with market prices reflecting the demand of power and available generating resources at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional operating companies, Southern Power and its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and therefore are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The FERC is also authorized to establish regional reliability organizations which are authorized to enforce reliability standards, to address impediments to the construction of transmission, and to prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 KWs and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 KWs.

In 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on Alabama Power's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to Alabama Power, under the terms and conditions of the existing license, until action is taken on the new license applications.

The FERC issued annual licenses to the Coosa developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow Alabama Power to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. Though the Coosa application remains pending before the FERC, in March 2010, the FERC issued a new 30 year license to Alabama Power for the Warrior River developments. In April 2010, the Smith Lake Improvement and Stakeholder Association filed a request for rehearing of the FERC order granting the new Warrior license. In May 2010, the FERC granted the rehearing request for the limited purpose of allowing the FERC additional time to consider the substantive issues raised in the request.

In 2006, Alabama Power initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. The current Martin license will expire on June 8, 2013. On June 8, 2011, Alabama Power filed an application with the FERC to relicense the Martin Dam Project.

In 2010, Alabama Power initiated the process of developing an application to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed with the FERC no later than August 31, 2013.

In 2007, Georgia Power began the relicensing process for Bartlett's Ferry which is located on the Chattahoochee River near Columbus, Georgia. The current Bartlett's Ferry license expires in 2014 and the application for a new license is expected to be submitted to the FERC in late 2012.

The ultimate outcome of these matters cannot be determined at this time. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Alabama Power in Item 7 herein for additional information.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 KW capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the period 2023-2034 in the case of Alabama Power's projects and in the period 2020-2039 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property.

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

In 2002, the NRC extended the licenses of Georgia Power's Plant Hatch Units 1 and 2 until 2034 and 2038, respectively. In 2005, the NRC extended the licenses of Alabama Power's Plant Farley Units 1 and 2 until 2037 and 2041, respectively. In 2009, the NRC extended the licenses of Plant Vogtle Units 1 and 2 to 2047 and 2049, respectively.

Also in 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of Georgia Power, OPC, MEAG Power, and Dalton (collectively, Owners), related to Plant Vogtle Units 3 and 4. In

2008, Southern Nuclear filed an application with the NRC for combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Electric Company LLC's Design Certification Document, as amended, for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Construction — Nuclear" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Georgia Power — Nuclear Construction" and Georgia Power under "Construction — Nuclear" in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

Environmental Statutes and Regulations

Southern Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions for the traditional operating companies or market-based rates for Southern Power. There is no assurance, however, that all such costs will be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to the Southern Company system, including laws and regulations designed to address air quality, water, management of waste materials and coal combustion byproducts, global climate change, or other environmental and health concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including, but not limited to, the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act, proposed and final regulations related to air quality, water, greenhouse gases, and coal combustion byproducts. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and climate change regulation.

The Southern Company system's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Southern Company system's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

As of December 31, 2011, the Southern Company system had total generating capacity of approximately 43,555 MWs, of which 20,212 MWs are coal-fired. Over the past several years, the Southern Company system has installed various pollution control technologies on coal-fired units, including both selective catalytic reduction equipment and scrubbers on the 17 largest coal units making up 11,036 MWs of the Southern Company system's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Southern Company system is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including its units with existing pollution control technologies), and changing fuel sources for certain units.

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SEGCO is also developing an environmental compliance strategy for its 1,000 MWs of coal-fired generating capacity, which may result in unit retirements, installation of controls, or changing fuel source. The capacity of SEGCO's units is sold to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on Southern Company's, Alabama Power's, or Georgia Power's financial statements. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

The traditional operating companies recover their respective costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the respective PSCs. Approved environmental compliance, storm damage, and certain other costs are recovered at Alabama Power, Gulf Power, and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power and Gulf Power through base rate proceedings.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company and each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rate mechanisms.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Construction — Nuclear" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Georgia Power — Nuclear Construction" and Georgia Power under "Construction – Nuclear" in Item 8 herein for a discussion of the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which allow Georgia Power to recover financing costs for construction of the new nuclear units during the construction period beginning in 2011.

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The traditional operating companies and Southern Power and its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

Integrated Resource Planning

Each of the traditional operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See "Environmental Statutes and Regulations" above for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional operating companies.

Certain of the traditional operating companies periodically file IRPs with their respective state PSC. The following is a summary of the most recent IRP filings by certain of the traditional operating companies.

Georgia Power

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to get cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct.

In January 2010, Georgia Power filed its 2010 IRP with the Georgia PSC. The 2010 IRP projected that Georgia Power's current supply-side and demand-side resources are sufficient to provide a cost-effective and reliable source of capacity and energy at least through 2014. The 2010 IRP identified a number of potential new or modified federal environmental statutes and regulations that could significantly impact Georgia Power's existing coal-fired generating units. In addition, under the State of Georgia's Multi-Pollutant Rule, Georgia Power is required to install specific emissions controls on certain coal-fired generating units by specific dates between December 31, 2008 and June 1, 2015. See "Environmental Statutes and Regulations" above.

In July 2010, the Georgia PSC approved Georgia Power's 2010 IRP including the following provisions: (1) restarting a request for proposal to enable the potential replacement of coal units that may be retired beginning in approximately 2015; (2) expanding energy efficiency efforts; (3) implementing seven new demand-side management and energy efficiency programs; (4) collecting incentives totaling 10% of the net benefit of energy efficiency programs annually, with certain conditions, for the certified programs; (5) developing a one MW self-build portfolio of solar photovoltaic demonstration projects; (6) delaying capital spending on the conversion of Plant Mitchell Unit 3 from a coal-fired generating unit to a renewable biomass generating unit until the EPA issues applicable maximum achievable control technology (MACT) standards under the Clean Air Act; (7) considering conversion of additional coal units to biomass, if such conversions appear to be economic and feasible; and (8) continuing to suspend work on environmental controls for Units 6 and 7 at Plant Yates and Units 3 and 4 at Plant Branch until the EPA issues applicable MACT standards and regulations for coal combustion byproducts.

In addition, Georgia Power's 2010 IRP reflected the construction of Plant McDonough Units 4, 5, and 6 (natural gas) and Plant Vogtle Units 3 and 4 (nuclear) as certified by the Georgia PSC in 2007 and 2009, respectively. The 2010 IRP also reflected the related retirement of Plant McDonough Units 1 and 2 (coal), which were decertified by the Georgia PSC in connection with construction of the new units. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Georgia Power — Nuclear Construction" and "Retail Regulatory Matters — Georgia Power — Other Construction" in Item 8 herein and Note 3 to the financial statements of Georgia Power under "Construction" in Item 8 herein for additional information.

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On August 4, 2011, Georgia Power filed an update to its IRP (2011 IRP Update). The filing included Georgia Power's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and to decertify and retire Plant Mitchell Unit 4C in March 2012. Georgia Power also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, Georgia Power is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 MWs of capacity. Georgia Power is currently updating its economic analysis of these units based on the final MATS rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, Georgia Power cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes Georgia Power's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015, from four PPAs selected through the 2015 request for proposal process.

In addition, Georgia Power filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with Georgia PSC. On January 30, 2012, Georgia Power entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with EPA rules and coal unit retirement decisions.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Gulf Power

Annually by April 1, Gulf Power must file a 10-year site plan with the Florida PSC containing Gulf Power's estimate of its power-generating needs in the period and the general location of its proposed power plant sites. The 10-year site plans submitted by the state's electric utilities are reviewed by the Florida PSC and subsequently classified as either "suitable" or "unsuitable." The Florida PSC then reports its findings along with any suggested revisions to the Florida Department of Environmental Protection for its consideration at any subsequent electrical power plant site certification proceedings. Under Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC. At least every five years, the Florida PSC must conduct proceedings to establish numerical goals for all investor-owned electric utilities and certain municipal or cooperative electric utilities in the state to reduce the growth rates of weather-sensitive peak demand, to reduce and control the growth rates of electric consumption, and to increase the conservation of expensive resources, such as petroleum fuels. Overall residential KWs and KWH goals and overall commercial/industrial KWs and KWH goals for each utility are set by the Florida PSC for each year over a 10-year period. The goals are to be based on an estimate of the total cost effective KWs and KWH savings reasonably achievable through demand-side management in each utility's service territory over a 10-year period. Once goals have been set, each affected utility must develop and submit plans and programs to meet the overall goals within its service territory to the Florida PSC for review and approval. Once approved, the utilities are required to submit periodic reports which the Florida PSC then uses to prepare its annual report to the Governor and Legislature of the goals that have been established and the progress towards meeting those goals.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" on November 22, 2011. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS —FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — Air Quality," "Environmental Matters – Environmental Statutes and Regulations — Coal Combustion Byproducts," and "Environmental Matters — Global Climate Issues" of Gulf Power in Item 7 herein. The site plan and environmental compliance plan include preliminary retirement studies under a variety of potential scenarios for units at each of Gulf Power's coal-fired generating plants. These studies indicate that, depending on the final requirements in these anticipated EPA regulations and any legislation or regulations relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Gulf Power may conclude that it is more economical to retire certain of its coal-fired generating units prior to 2021 and to replace such units with new or purchased capacity.

In 2009, the Florida PSC adopted new numerical conservation goals for Gulf Power along with other electric utilities in the state. The Florida PSC adopted more aggressive goals due in part to the consideration of possible greenhouse gas emissions costs incurred in connection with possible climate change legislation and a change in the manner in which the Florida PSC considers the effect of so-called “free-riders” on the level of conservation reasonably achievable through utility programs. Gulf Power’s plans and programs to meet the new goals were submitted to the Florida PSC for review in March 2010 and were approved on January 25, 2011. The costs of implementing Gulf Power’s conservation plans and programs are recovered through specific conservation recovery rates set annually by the Florida PSC.

The ultimate outcome of these matters cannot be determined at this time.

Mississippi Power

In 2009, Mississippi Power filed its 2010 IRP with the Mississippi PSC. The filing was made in connection with the Mississippi PSC certification proceedings relating to the Kemper IGCC. In the 2010 IRP, Mississippi Power projected that it will have a need for new capacity in the 2013 to 2015 timeframe. The 2010 IRP indicated a need range of approximately 200 MWs to 300 MWs in 2014, which reflects growth in load and the anticipated retirement of older gas steam units Plant Eaton Units 1 through 3 and Plant Watson Units 1 through 3 in 2012 and 2013, respectively. In addition, due to potential retirements of existing coal units, the Mississippi PSC found a need in 2015 that ranges from 304 MWs to 1,276 MWs.

The range of needs for 2015 is based on Mississippi Power’s preliminary analysis of the MATS rule, as well as potential legislation or regulations that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT’S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — “Environmental Matters — Environmental Statutes and Regulations — Air Quality” and “Environmental Matters — Global Climate Issues” of Mississippi Power in Item 7 herein. Depending on Mississippi Power’s final assessment of the MATS rule, the final requirements in the anticipated EPA regulations, and any legislation or regulation relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Mississippi Power may conclude that it is more economical to discontinue burning coal at certain coal-fired generating units than to install the required controls.

Mississippi Power’s 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4.

The ultimate outcome of these matters cannot be determined at this time.

Mississippi Base Load Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor in 2008 to enhance the Mississippi PSC’s authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. The effect of this legislation on Southern Company and Mississippi Power cannot be determined at this time.

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In May 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming Mississippi Power's application for a certification of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN. The estimated cost of the plant is $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2. The Mississippi PSC's order (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in the Mississippi Power proposal, and (3) approved financing cost recovery on construction work in progress (CWIP) balances, which provided for the accrual of an allowance for funds used during construction in 2010 and 2011 and provides for the recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by Mississippi Power in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

On April 27, 2011 and August 9, 2011, Mississippi Power submitted to the Mississippi PSC proposed rate schedules detailing Certificated New Plant-A (CNP-A) and Certificated New Plant-B (CNP-B), respectively. CNP-A and CNP-B are proposed cost recovery mechanisms authorized by the Baseload Act. CNP-A is designed specifically to recover financing costs during the construction phase of the Kemper IGCC and CNP-B is designed to govern rates after the Kemper IGCC is placed into commercial service.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters — Certificated New Plant" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle" and Mississippi Power under "Retail Regulatory Matters — Certificated New Plant" in Item 8 herein for additional information.

The ultimate outcome of these matters cannot be determined at this time.

Employee Relations

The Southern Company system had a total of 26,377 employees on its payroll at December 31, 2011.

	Employees at December 31, 2011
Alabama Power	6,632
Georgia Power	8,310
Gulf Power	1,424
Mississippi Power	1,264
SCS	4,533
Southern Nuclear	3,933
Southern Power*	0
Other	281
Total	26,377

* Southern Power has no employees. Southern Power has agreements with SCS and the traditional operating companies whereby employee services are rendered at amounts in compliance with FERC regulations.

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

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Alabama Power has an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2016.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through September 14, 2014.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014.

Southern Nuclear and the IBEW ratified a new five-year labor agreement for certain employees at Plants Hatch and Vogtle on September 16, 2011. The agreement is effective through June 30, 2016. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley, which was ratified in 2009, remains in effect through August 15, 2014.

The agreements also make the terms of the pension plans for the companies discussed above subject to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

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Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, and the operation of fossil-fuel, hydroelectric, solar, and nuclear generating facilities, as well as transmission and distribution facilities. For example, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected absent the ability to conduct business pursuant to FERC market-based rate authority. Additionally, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. While the retail rates of the traditional operating companies are designed to provide for the full recovery of costs (including a reasonable return on invested capital), there can be no assurance that a state PSC, in a future rate proceeding, will not attempt to alter the timing or amount of certain costs for which recovery is sought or to modify the current authorized rate of return.

Southern Company and its subsidiaries believe the necessary permits, approvals, and certificates have been obtained for their respective existing operations and that their respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, water, coal combustion byproducts, global climate change, renewable energy standards, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, or Southern Power.

The Southern Company system is subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management of hazardous and solid waste in order to adequately protect the environment. Compliance with these environmental requirements requires the traditional operating companies and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at substantially all of their respective facilities. These expenditures are significant and Southern Company, the traditional operating companies, and Southern Power expect that they will increase in the future. Through 2011, the traditional operating companies had invested approximately $8.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $300 million, $500 million, and $1.3 billion for 2011, 2010, and 2009, respectively.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, water, coal combustion byproducts, global climate change, or other environmental and health concerns may be adopted or become applicable to the traditional operating companies and Southern Power.

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During 2011, the EPA proposed revisions and revised or issued additional regulations and designations with respect to air quality under the Clean Air Act, including finalization of the eight-hour ozone standards, the CSAPR, which relates to nitrogen oxide and sulfur dioxide emissions, and the MATS rule for coal- and oil-fired electric generating units, which imposes stringent emissions limits for acid gases, mercury, and total particulate matter.

On April 20, 2011, the EPA published a proposed water quality rule relating to cooling water intake structures at existing power plants and manufacturing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the traditional operating companies' generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers.

In addition, the EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements and impact of the beneficial reuse of coal combustion byproducts. Under both options, the EPA proposes to exempt the beneficial use of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012. The ultimate outcome of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of CAIR, which calls for phased reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. On August 8, 2011, the EPA adopted the CSAPR to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide additional increases to certain state emissions budgets, including the States of Florida, Georgia, and Mississippi.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and total particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule.

The Southern Company system is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. The Southern Company system's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described above; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Southern Company system's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time. Additional compliance costs (including costs for the installation of environmental controls) and costs related to potential unit retirements and replacements could affect results of operations, cash flows, and financial condition if such costs are not recovered from customers. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

If Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines. The EPA has filed civil actions against Alabama Power and Georgia Power and issued notices of violation to Gulf Power and Mississippi Power alleging violations of the new source review provisions of the Clean Air Act. Southern Company, the traditional operating companies (excluding Mississippi Power), and Southern Power are also parties to suits alleging that emissions of carbon dioxide, a greenhouse gas, contribute to global climate change. An adverse outcome in any of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates for the traditional operating companies or market-based rates for Southern Power.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent.

The ultimate cost impact of proposed and final legislation and regulations and litigation are likely to result in significant and additional costs and could result in additional operating restrictions.

The regional power market in which the Southern Company system competes may have changing transmission regulatory structures, which could affect the ownership of these assets and related revenues and expenses.

The traditional operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. Ongoing FERC efforts that may potentially change the regulatory and/or operational structure of transmission could have an adverse impact on future revenues. In addition, pending FERC regulation pertaining to cost allocation could require Southern Company and its utility subsidiaries to subsidize costs outside of the Southern Company system’s retail service territory. The financial condition, net income, and cash flows of Southern Company and its utility subsidiaries could be adversely affected by pending or future changes in the federal regulatory or operational structure of transmission.

The traditional operating companies and Southern Power could be subject to higher costs and penalties as a result of mandatory reliability standards.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power systems, including the traditional operating companies, are subject to mandatory reliability standards enacted by the North American Reliability Corporation and enforced by the FERC. Compliance with the mandatory reliability standards may subject the traditional operating companies, Southern Power, and Southern Company to higher operating costs and may result in increased capital expenditures. In addition, the MATS rule imposes stringent emission limits for acid gases, mercury, and total particulate matter on coal- and oil-fired electric utility steam generating units. There is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the MATS rule within the compliance period, and the limited compliance period could significantly affect electric system reliability and thus impact the ability of the traditional operating companies and Southern Power to comply with mandatory reliability standards. If any traditional operating company or Southern Power is found to be in noncompliance with the mandatory reliability standards, such traditional operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

OPERATIONAL RISKS

The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of its subsidiaries' electric generating, transmission, and distribution facilities. Operating these facilities involves many risks, including:

- operator error or failure of equipment or processes, particularly with older generating facilities;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks;
- fuel or material supply interruptions;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- implementation of technologies with which the Southern Company system is developing experience;
- information technology system failure;
- cyber intrusion; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business model of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central station power electric production. If this were to happen and if these technologies achieved economies of scale, the market share of the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power.

Operation of nuclear facilities involves inherent risks, including environmental, health, regulatory, natural disasters, terrorism, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8.4%, of Southern Company's generation capacity as of December 31, 2011. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, health, and financial risks such as:

- the potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of spent nuclear fuel;
- uncertainties with respect to the on-site storage of and the ability to dispose of spent nuclear fuel;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain adequate reserves for decommissioning;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of others in the United States;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- the threat of a possible terrorist attack; and
- the impact of a natural disaster.

Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. As a result of the major earthquake and tsunami that struck Japan on March 11, 2011 and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time.

In the event of non-compliance with NRC licensing and safety-related requirements, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, although Alabama Power, Georgia Power, and Southern Company have no reason to anticipate a serious nuclear incident at the Southern Company system nuclear plants, if an incident did occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the United States could require Alabama Power and Georgia Power to make material contributory payments.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult to predict.

Physical or cyber attacks, both threatened and actual, could impact the ability of the traditional operating companies and Southern Power to operate and could adversely affect financial results and liquidity.

The traditional operating companies and Southern Power face the risk of physical and cyber attacks, both threatened and actual, against their respective generation facilities, the transmission and distribution infrastructure used to transport power, and their information technology systems and network infrastructure, which could negatively impact the ability of the traditional operating companies or Southern Power to generate, transport, and deliver power, or otherwise operate their respective facilities in the most efficient manner or at all.

The traditional operating companies and Southern Power operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional grid. In addition, in the ordinary course of business, the traditional operating companies and Southern Power collect and retain sensitive information including personal identification information about customers and employees and other confidential information. Despite the implementation of security measures, all technology systems are potentially vulnerable to disability, failures, or unauthorized access due to human error or physical or cyber attacks. If the traditional operating companies' or Southern Power's technology systems were to fail or be breached and were not recovered in a timely way, the traditional operating companies or Southern Power may be unable to fulfill critical business functions, and sensitive and other data could be compromised. The theft, damage, or improper disclosure of sensitive electronic data may also subject the applicable traditional operating company or Southern Power to penalties and claims from third parties.

These events could negatively affect the financial results of Southern Company, the traditional operating companies, or Southern Power through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies are dependent on coal for much of their electric generating capacity. Each traditional operating company has coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be fully recoverable through rates.

In addition, the traditional operating companies and Southern Power to a greater extent are dependent on natural gas for a portion of their electric generating capacity. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane.

In addition, world market conditions for fuels can impact the cost and availability of natural gas, coal, and uranium.

The revenues of Southern Company, the traditional operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, or the failure to renew the PPAs, could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. Even though Southern Power and the traditional operating companies have a rigorous credit evaluation process, the failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although these credit evaluations take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than the credit evaluation predicts. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If a PPA is not renewed, a replacement PPA cannot be assured.

Failure to attract and retain an appropriately qualified workforce could negatively impact Southern Company's and its subsidiaries' results of operations.

Events such as an aging workforce without appropriate replacements, mismatch of skillset to future needs, or unavailability of contract resources may lead to operating challenges or increased costs. Such operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development, especially with the workforce needs associated with new nuclear and IGCC construction. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

Southern Company, the traditional operating companies, and Southern Power may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the traditional operating companies and Southern Power require ongoing capital expenditures, including those to meet environmental standards.

The businesses of the registrants require substantial capital expenditures for investments in new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company intends to continue its strategy of developing and constructing other new facilities, including new nuclear generating, combined cycle, IGCC, and biomass generating units, expanding existing facilities, and adding environmental control equipment. These types of projects are long-term in nature and may involve facility designs that have not been finalized or previously constructed. The completion of these types of projects without delays or significant cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- work stoppages;
- contractor or supplier delay or non-performance under construction or other agreements;

- delays in or failure to receive necessary permits, approvals, and other regulatory authorizations;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- continued public and policymaker support for such projects;
- adverse weather conditions;
- unforeseen engineering problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor.

In addition, with respect to the construction of new nuclear units and the operation of existing nuclear units, a major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. As a result of the major earthquake and tsunami that struck Japan on March 11, 2011 and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company.

Construction delays also may result in the loss of otherwise available investment tax credits and other tax incentives. Furthermore, if construction projects are not completed according to specification, a traditional operating company or Southern Power and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the construction of the Kemper IGCC. Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4. Georgia Power owns 45.7% of the new units, with a certified cost of approximately $6.1 billion. The Georgia PSC has approved Georgia Power's total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. Georgia Power will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period. The COLs for Plant Vogtle Units 3 and 4 were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to obtain commercial operation in 2016 and 2017, respectively. During the course of construction activities, issues have materialized that may impact the project budget and schedule, including potential costs associated with compressing the project schedule to meet the projected commercial operation dates. In addition, there have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4. Similar additional challenges at the state and federal level are expected as construction proceeds. The ultimate outcome of these matters cannot be determined at this time.

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In addition, Mississippi Power is constructing the Kemper IGCC. In July 2010, Mississippi Power and SMEPA entered into an Asset Purchase Agreement whereby SMEPA agreed to purchase a 17.5% undivided ownership interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. The estimated cost of the plant is $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2. The Mississippi PSC order approving the Kemper IGCC included a construction cost cap of $2.88 billion (excluding the cost of the lignite mine equipment and the carbon dioxide pipeline facilities) and provides for the establishment of operational cost and revenue parameters based upon the assumptions in Mississippi Power's proposal. As of December 31, 2011, Mississippi Power had spent a total of approximately $943.3 million on the Kemper IGCC, including regulatory filing costs. The ultimate outcome of these matters cannot be determined at this time.

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide reliable operations.

FINANCIAL, ECONOMIC, AND MARKET RISKS

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, that may reduce Southern Company's, the traditional operating companies', and Southern Power's revenues and increase costs.

The generation operations and energy marketing operations of the Southern Company system are subject to changes in power prices or fuel costs, which could increase the cost of producing power or decrease the amount received from the sale of power. The market prices for these commodities may fluctuate significantly over relatively short periods of time. In addition, the proportion of natural gas generation to the total fuel mix is likely to increase in the future. The Southern Company system attempts to mitigate risks associated with fluctuating fuel costs by passing these costs on to customers through the traditional operating companies' fuel cost recovery clauses or through PPAs. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;

- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional operating companies or Southern Power and Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

Historically, the traditional operating companies from time to time have experienced underrecovered fuel cost balances and deficits in their storm cost recovery reserve balances and may experience such balances and deficits in the future. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel cost recovery clauses and storm recovery costs through special rate provisions administered by the respective PSCs, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating company and Southern Company.

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds.

A downgrade in the credit ratings of Southern Company, the traditional operating companies, or Southern Power could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional operating companies, or Southern Power to post collateral or replace certain indebtedness.

There are a number of factors that rating agencies evaluate to arrive at credit ratings for Southern Company, the traditional operating companies, and Southern Power, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional operating companies, and Southern Power could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or Southern Company, the traditional operating companies, or Southern Power has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade Southern Company, the traditional operating companies, or Southern Power, borrowing costs would increase, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts.

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The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures. These risk management policies, limits, and procedures might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered for hedging purposes might not off-set the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Southern Company and its subsidiaries. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with a changing economic environment as well as the financial stability of the customers of the traditional operating companies and Southern Power.

Southern Company, the traditional operating companies, and Southern Power are exposed to risks related to general economic conditions in their applicable service territory and are thus impacted by the economic cycles of the customers each serves. Any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of the customers and counterparties of the traditional operating companies and Southern Power. As territories served by the traditional operating companies and Southern Power experience economic downturns, energy consumption patterns may change and revenues may be negatively impacted. Customer growth and customer usage can be affected by economic factors in the service territory of the traditional operating companies and Southern Power and elsewhere, including, for example, job and income growth, housing starts, and new home prices. Adverse economic conditions, a population decline, and/or business closings in the territory served by the traditional operating companies or Southern Power or slower than anticipated customer growth as a result of a recessionary economy or otherwise could also have a negative impact on revenues and could result in greater expense for uncollectible customer balances.

As with other parts of the country, the territories served by the traditional operating companies and Southern Power have been impacted by the recent economic recession. The traditional operating companies have experienced residential and commercial sales that continue to be below historical trends due to the recent economic recession. Southern Power is expected to continue to experience reduced future revenues for its requirements customers due to the recent economic recession. The timing and extent of the recovery cannot be predicted.

Stronger or more rapid than expected economic growth, coupled with the effects of current and future environmental regulations applicable to the traditional operating companies or Southern Power, could impact the ability of the traditional operating companies and Southern Power to meet the energy demands of their customers. Weaker or slower than expected economic growth could have a negative impact on revenues, could result in greater expense for uncollected customer balances, and could adversely impact the value of generation assets of the traditional operating companies and Southern Power.

All of the factors discussed above could adversely affect Southern Company's, the traditional operating companies', and Southern Power's level of future net income.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation facilities.

The traditional operating companies and Southern Power are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional operating companies or Southern Power purchase capacity on the open market or build additional generation facilities. Because regulators may not permit the traditional operating companies to pass all of these purchase or construction costs on to their customers, the traditional operating companies may not be able to recover any of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

Demand for power could decrease or fail to grow at expected rates, resulting in stagnant or reduced revenues, limited growth opportunities, and potentially stranded generation assets.

Southern Company, the traditional operating companies, and Southern Power each engage in a long-term planning process to determine the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power may not be able to extend its existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or it may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

Energy conservation and energy price increases could negatively impact financial results.

Customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income, increases in energy price, or individual conservation efforts. In addition, a number of regulatory and legislative bodies have proposed or introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. For example, if any traditional operating company is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional operating company and Southern Company.

Certain of the traditional operating companies actively promote energy conservation programs, which have been approved by their respective state PSCs. Regulatory mechanisms have been established that provide for the recovery of costs related to such programs and lost revenues as a result of such programs. However, to the extent conservation results in reduced energy demand or significantly slows the growth in demand beyond what is anticipated, the value of generation assets of the traditional operating companies and Southern Power and other unregulated business activities could be adversely impacted and the traditional operating companies could be negatively impacted depending on the regulatory treatment of the associated impacts. In addition, the failure of those traditional operating companies who actively promote energy conservation programs to achieve the energy conservation targets established by their respective state PSCs could negatively impact such traditional operating company's ability to recover costs and receive certain benefits related to such programs.

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Additionally, Southern Company, the traditional operating companies, and Southern Power could also be negatively impacted if any future energy price increases result in a decrease in customer usage.

Southern Company, the traditional operating companies, and Southern Power are unable to determine what impact, if any, conservation and increases in energy prices will have on their respective financial condition or results of operations.

The operating results of Southern Company, the traditional operating companies, and Southern Power are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, significant weather events, such as hurricanes, tornadoes, floods, and droughts could result in substantial damage to or limit the operation of the properties of the traditional operating companies and Southern Power and could negatively impact results of operation, financial condition, and liquidity.

Electric power supply is generally a seasonal business. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power may fluctuate substantially on a seasonal basis. In addition, the traditional operating companies and Southern Power have historically sold less power when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, available cash, and borrowing ability of Southern Company, the traditional operating companies, and Southern Power.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions which could be subject to major storm activity. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

Each traditional operating company maintains a reserve for property damage to cover the cost of damages from weather events to its transmission and distribution lines and the cost of uninsured damages to its generating facilities and other property. In the event a traditional operating company experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. While the traditional operating companies generally are entitled to recover prudently incurred costs incurred in connection with such an event, any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company’s and Southern Company’s results of operations, financial condition, and liquidity.

In addition, damages resulting from significant weather events within the service territory of any traditional operating company or affecting Southern Power’s customers may result in the loss of customers and reduced demand for electricity for extended periods. For example, Hurricane Katrina hit the Gulf Coast of Mississippi in 2005 and caused substantial damage within Mississippi Power’s service territory. As of December 31, 2011, Mississippi Power had over 8,300 fewer retail customers as compared to pre-storm levels due to obstacles in the rebuilding process as a result of the storm, coupled with the recessionary economy. Any significant loss of customers or reduction in demand for electricity could have a material negative impact on a traditional operating company’s, Southern Power’s, and Southern Company’s results of operations, financial condition, and liquidity.

The business of Southern Company, the traditional operating companies, and Southern Power is dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional operating company, or Southern Power to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional operating companies, and Southern Power rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional operating company, or Southern Power is not able to access capital at competitive rates, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional operating companies, and Southern Power rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of Southern Company, the traditional operating companies, and Southern Power believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- the bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, both nationally and internationally;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company’s facilities or unrelated energy companies’ facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

Market performance and other changes may decrease the value of benefit plans and nuclear decommissioning trust assets or may increase plan costs, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust under Southern Company’s pension and postretirement benefit plans and the assets held in trust to satisfy obligations to decommission Alabama Power’s and Georgia Power’s nuclear plants. Southern Company, Alabama Power, and Georgia Power have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected return rates. A decline in the market value of these assets, as has been experienced in prior periods, may increase the funding requirements relating to benefit plan liabilities of the Southern Company system and Alabama Power’s and Georgia Power’s nuclear decommissioning obligations. Additionally, changes in interest rates affect the liabilities under pension and postretirement benefit plans of the Southern Company system; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. Southern Company and its subsidiaries are also facing rising medical benefit costs, including the current costs for active and retired employees. It is possible that these costs may increase at a rate that is significantly higher than anticipated. If the Southern Company system is unable to successfully manage benefit plan assets and medical benefit costs and Alabama Power and Georgia Power are unable to successfully manage the nuclear decommissioning trust funds, results of operations and financial position could be negatively affected.

Southern Company may be unable to recover its investment in its leveraged leases if a lessee fails to profitably operate the leased assets.

Southern Company has several leveraged lease agreements, with terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. With respect to Southern Company's investments in leveraged leases, the recovery of its investment is dependent on the profitable operation of the leased assets by the respective lessees. A significant deterioration in the performance of the leased asset could result in the impairment of the related lease receivable.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with their ability to obtain adequate insurance.

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, while Southern Company, the traditional operating companies, and Southern Power maintain an amount of insurance protection that they consider adequate, there is no guarantee that the insurance policies selected by them will cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance could adversely affect the results of operations, cash flows, or financial condition of Southern Company, the traditional operating companies, or Southern Power.

The net income of Southern Company, the traditional operating companies, and Southern Power could be negatively impacted by a wholesale electric market structure in which Southern Company could not be competitive with other market participants.

Competition at the wholesale level continues to evolve in the electricity markets. As a result of changes in federal law, regulatory uncertainty, and industry restructuring, competing in the wholesale electricity markets has become more challenging. FERC rules related to transmission are intended to spur the development of new transmission infrastructure as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers, including initiatives designed to promote and encourage the integration of renewable sources of supply. However, transmission regulation impacts wholesale transaction structures, and generation regulation may impact wholesale markets. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

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Item 2. PROPERTIES

Electric Properties

The traditional operating companies, Southern Power, and SEGCO, at December 31, 2011, owned and/or operated 33 hydroelectric generating stations, 34 fossil fuel generating stations, three nuclear generating stations, and 13 combined cycle/cogeneration stations, two solar facilities, and one landfill gas facility. The amounts of capacity for each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1) (KWs)
FOSSIL STEAM		
Gadsden	Gadsden, AL	120,000
Gorgas	Jasper, AL	1,221,250
Barry	Mobile, AL	1,525,000
Greene County	Demopolis, AL	300,000(2)
Gaston Unit 5	Wilsonville, AL	880,000
Miller	Birmingham, AL	2,532,288(3)
Alabama Power Total		6,578,538
Bowen	Cartersville, GA	3,160,000
Branch	Milledgeville, GA	1,539,700(4)
Hammond	Rome, GA	800,000
Kraft	Port Wentworth, GA	281,136
McDonough Unit 1	Atlanta, GA	245,000(5)
McIntosh	Effingham County, GA	163,117
McManus	Brunswick, GA	115,000
Mitchell	Albany, GA	125,000
Scherer	Macon, GA	750,924(6)
Wansley	Carrollton, GA	925,550(7)
Yates	Newnan, GA	1,250,000
Georgia Power Total		9,355,427
Crist	Pensacola, FL	970,000
Daniel	Pascagoula, MS	500,000(8)
Lansing Smith	Panama City, FL	305,000
Scholz	Chattahoochee, FL	80,000
Scherer Unit 3	Macon, GA	204,500(6)
Gulf Power Total		2,059,500
Daniel	Pascagoula, MS	500,000(8)
Eaton	Hattiesburg, MS	67,500
Greene County	Demopolis, AL	200,000(2)
Sweatt	Meridian, MS	80,000
Watson	Gulfport, MS	1,012,000
Mississippi Power Total		1,859,500
Gaston Units 1-4	Wilsonville, AL	
SEGCO Total		1,000,000(9)
Total Fossil Steam		20,852,965
NUCLEAR STEAM		
Farley	Dothan, AL	
Alabama Power Total		1,720,000
Hatch	Baxley, GA	899,612(10)
Vogtle	Augusta, GA	1,060,240(11)
Georgia Power Total		1,959,852
Total Nuclear Steam		3,679,852
COMBUSTION TURBINES		
Greene County	Demopolis, AL	
Alabama Power Total		720,000

Boulevard	Savannah, GA	59,100
Bowen	Cartersville, GA	39,400
Intercession City	Intercession City, FL	47,667(12)
Kraft	Port Wentworth, GA	22,000
McDonough Unit 3	Atlanta, GA	78,800
McIntosh Units 1 through 8	Effingham County, GA	640,000
McManus	Brunswick, GA	481,700
Mitchell	Albany, GA	118,200(13)
Robins	Warner Robins, GA	158,400
Wansley	Carrollton, GA	26,322(7)
Wilson	Augusta, GA	354,100
Georgia Power Total		2,025,689
Lansing Smith Unit A	Panama City, FL	39,400
Pea Ridge Units 1-3	Pea Ridge, FL	15,000
Gulf Power Total		54,400
Chevron Cogenerating Station	Pascagoula, MS	147,292(14)
Sweatt	Meridian, MS	39,400

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Generating Station	Location	Nameplate Capacity (1)
		(KWs)
Watson	Gulfport, MS	39,360
Mississippi Power Total		226,052
Dahlberg	Jackson County, GA	756,000
Oleander	Cocoa, FL	791,301
Rowan	Salisbury, NC	455,250
West Georgia	Thomaston, GA	668,800
Southern Power Total		2,671,351
Gaston **(SEGCO)**	Wilsonville, AL	19,680(9)
Total Combustion Turbines		5,717,172
COGENERATION		
Washington County	Washington County, AL	123,428
GE Plastics Project	Burkeville, AL	104,800
Theodore	Theodore, AL	236,418
Total Cogeneration		464,646
COMBINED CYCLE		
Barry	Mobile, AL	
Alabama Power Total		1,070,424
McIntosh Units 10&11	Effingham County, GA	1,318,920
McDonough Unit 4	Atlanta, GA	840,000
Georgia Power Total		2,158,920
Smith	Lynn Haven, FL	
Gulf Power Total		545,500
Daniel	Pascagoula, MS	
Mississippi Power Total		1,070,424
Franklin	Smiths, AL	1,857,820
Harris	Autaugaville, AL	1,318,920
Rowan	Salisbury, NC	530,550
Stanton Unit A	Orlando, FL	428,649(15)
Wansley	Carrollton, GA	1,073,000
Southern Power Total		5,208,939
Total Combined Cycle		10,054,207
HYDROELECTRIC FACILITIES		
Bankhead	Holt, AL	53,985
Bouldin	Wetumpka, AL	225,000
Harris	Wedowee, AL	132,000
Henry	Ohatchee, AL	72,900
Holt	Holt, AL	46,944
Jordan	Wetumpka, AL	100,000
Lay	Clanton, AL	177,000
Lewis Smith	Jasper, AL	157,500
Logan Martin	Vincent, AL	135,000
Martin	Dadeville, AL	182,000
Mitchell	Verbena, AL	170,000
Thurlow	Tallassee, AL	81,000
Weiss	Leesburg, AL	87,750
Yates	Tallassee, AL	47,000
Alabama Power Total		1,668,079
Bartletts Ferry	Columbus, GA	173,000
Goat Rock	Columbus, GA	38,600
Lloyd Shoals	Jackson, GA	14,400
Morgan Falls	Atlanta, GA	16,800
North Highlands	Columbus, GA	29,600

Oliver Dam	Columbus, GA	60,000
Rocky Mountain	Rome, GA	215,256(16)
Sinclair Dam	Milledgeville, GA	45,000
Tallulah Falls	Clayton, GA	72,000
Terrora	Clayton, GA	16,000
Tugalo	Clayton, GA	45,000
Wallace Dam	Eatonton, GA	321,300
Yonah	Toccoa, GA	22,500
6 Other Plants		18,080
Georgia Power Total		1,087,536
Total Hydroelectric Facilities		2,755,615
RENEWABLE SOURCES:		
SOLAR FACILITIES		
Cimarron	Springer, NM	
Southern Power Total		27,360(17)
Dalton	Dalton, GA	
Georgia Power Total		350
Total Solar		27,710
LANDFILL GAS FACILITY		
Perdido	Escambia County, FL	
Gulf Power Total		3,200
Total Generating Capacity		43,555,367

Notes:

(1) See “Jointly-Owned Facilities” herein for additional information.

(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.
(3) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.
(4) Branch Units 1 and 2 are scheduled to be retired on December 31, 2013 and October 1, 2013, respectively.
(5) McDonough Unit 1 (245,000 KWs) is scheduled to be retired in April 2012.
(6) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.
(7) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.
(8) Represents 50% of the plant which is owned as tenants in common by Gulf Power and Mississippi Power.
(9) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.
(10) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.
(11) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.
(12) Capacity shown represents 33 1/3% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Progress Energy Florida operates the unit.
(13) Mitchell Unit 4C (39,400 KWs) is scheduled to be retired in March 2012.
(14) Generation is dedicated to a single industrial customer.
(15) Capacity shown is Southern Power's portion (65%) of total plant capacity.
(16) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.
(17) Capacity shown is Southern Power's portion (90%) of the total plant capacity.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2011, the unamortized portion of this cost was approximately $18.3 million.

In 2011, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 36,956,000 KWs and occurred on August 3, 2011. The all-time maximum demand of 38,777,000 KWs on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in 2011 was 19.2%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information on peak demands for each registrant.

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Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power have undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Progress Energy Florida	Southern Power	OUC	FMPA	KUA
	(MWs)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	—%	—%	—%	—%	—%	—%	—%	—%	—%
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—	—
Intercession City, FL	143	—	—	33.3	—	—	—	66.7	—	—	—	—
Plant Stanton A	660	—	—	—	—	—	—	—	65%	28%	3.5%	3.5%

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A.

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments — Purchased Power Commitments" in Item 8 herein for additional information.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens pursuant to pollution control revenue bonds of Alabama Power and Gulf Power on specific pollution control facilities and liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4. See Note 6 to the financial statements of Southern Company, Alabama Power, Gulf Power, and Mississippi Power under "Assets Subject to Lien" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines and steam heating mains are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

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Item 3. LEGAL PROCEEDINGS

(1) United States of America v. Alabama Power (United States District Court for the Northern District of Alabama)

United States of America v. Georgia Power (United States District Court for the Northern District of Georgia)

See Note 3 to the financial statements of Southern Company and each traditional operating company under "Environmental Matters – New Source Review Actions" in Item 8 herein for information.

(2) Comer, et al. v. Murphy Oil USA, Inc. (United States District Court for the Southern District of Mississippi)

See Note 3 to the financial statements of Alabama Power, Georgia Power, Gulf Power, and Southern Power under "Climate Change Litigation – Hurricane Katrina Case" in Item 8 herein for information.

(3) Environmental Remediation

See Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Environmental Matters – Environmental Remediation" in Item 8 herein for information related to environmental remediation.

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2011.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 54
Elected in 2003. Chairman and Chief Executive Officer since December 1, 2010 and President since August 1, 2010. Previously served as Executive Vice President and Chief Operating Officer from February 2008 through July 31, 2010. He also served as Executive Vice President and Chief Financial Officer from May 2007 through January 2008 and Executive Vice President, Chief Financial Officer, and Treasurer from April 2003 to May 2007.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 57
Elected in 2010. Executive Vice President and Chief Financial Officer since August 13, 2010. Previously served as Executive Vice President, Chief Financial Officer, and Treasurer of Alabama Power from February 2005 through August 12, 2010.

W. Paul Bowers
Executive Vice President
Age 55
Elected in 2001. Chief Executive Officer, President, and Director of Georgia Power since December 31, 2010 and Chief Operating Officer of Georgia Power from August 13, 2010 to December 31, 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 12, 2010. He also served as Executive Vice President of Southern Company from May 2007 to February 2008 and as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008.

Mark A. Crosswhite
President and Chief Executive Officer of Gulf Power
Age 49
Elected in 2010. President, Chief Executive Officer, and Director of Gulf Power since January 1, 2011. Previously served as Executive Vice President of External Affairs at Alabama Power from February 2008 through December 2010 and Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008. He also served as Vice President of SCS from March 2004 through January 2008.

Edward Day, VI
President and Chief Executive Officer of Mississippi Power
Age 51
Elected in 2010. President, Chief Executive Officer, and Director of Mississippi Power since August 13, 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 12, 2010.

G. Edison Holland, Jr.
Executive Vice President, General Counsel, and Secretary
Age 59
Elected in 2001. Secretary since April 2005 and Executive Vice President and General Counsel since April 2001.

Stephen E. Kuczynski
President and Chief Executive Officer of Southern Nuclear
Age 49
Elected in 2011. President and Chief Executive Officer of Southern Nuclear since July 11, 2011. Before joining Southern Company, Mr. Kuczynski served at Exelon Corporation as the Senior Vice President of Engineering and Technical Services for Exelon Nuclear from February 2006 to June 2011.

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Charles D. McCrary
Executive Vice President
Age 60
Elected in 1998. Executive Vice President since February 2002. He also serves as President, Chief Executive Officer, and Director of Alabama Power since October 2001.

Susan N. Story
Executive Vice President
Age 51
Elected in 2003. President and Chief Executive Officer of SCS since January 1, 2011. Previously served as President, Chief Executive Officer, and Director of Gulf Power from April 2003 through December 2010.

Anthony J. Topazi
Executive Vice President and Chief Operating Officer
Age 61
Elected in 2003. Executive Vice President and Chief Operating Officer since August 13, 2010. Previously served as President, Chief Executive Officer, and Director of Mississippi Power from January 2004 through August 12, 2010.

Christopher C. Womack
Executive Vice President
Age 53
Elected in 2008. Executive Vice President and President of External Affairs since January 1, 2009. Previously served as Executive Vice President of External Affairs of Georgia Power from March 2006 through December 2008.

The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 25, 2011) for one year or until their successors are elected and have qualified, except for Mr. Kuczynski whose election was effective July 11, 2011.

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EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2011.

Charles D. McCrary
President, Chief Executive Officer, and Director
Age 60
Elected in 2001. President, Chief Executive Officer, and Director since October 2001. Since February 2002, he has also served as Executive Vice President of Southern Company.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 52
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 13, 2010. Previously served as Vice President and Chief Financial Officer of Gulf Power from May 2008 to August 12, 2010 and as Vice President and Comptroller of Alabama Power from January 2005 to April 2008.

Zeke W. Smith
Executive Vice President
Age 52
Elected in 2010. Executive Vice President of External Affairs since November 8, 2010. Previously served as Vice President of Regulatory Services and Financial Planning from February 2005 to November 2010.

Steven R. Spencer
Executive Vice President
Age 56
Elected in 2001. Executive Vice President of the Customer Service Organization since February 1, 2008. Previously served as Executive Vice President of External Affairs from 2001 through January 2008.

Theodore J. McCullough
Senior Vice President and Senior Production Officer
Age 48
Elected in 2010. Senior Vice President and Senior Production Officer since June 30, 2010. Previously served as Vice President and Senior Production Officer of Gulf Power from September 2007 until June 2010, and Manager of Georgia Power’s Plant Branch from December 2003 to August 2007.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on April 22, 2011 for one year or until their successors are elected and have qualified.

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EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2011.

W. Paul Bowers
President, Chief Executive Officer, and Director
Age 55
Elected in 2010. Chief Executive Officer, President, and Director since December 31, 2010 and Chief Operating Officer of Georgia Power from August 13, 2010 to December 31, 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 12, 2010. He also served as Executive Vice President of Southern Company from May 2007 to February 2008 and as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008.

W. Craig Barrs
Executive Vice President
Age 54
Elected in 2008. Executive Vice President of External Affairs since January 2010. Previously served as Senior Vice President of External Affairs from January 2009 to January 2010, Vice President of Governmental and Regulatory Affairs from April 2008 to December 2008, and Vice President of the Coastal Region from August 2006 to March 2008.

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer
Age 58
Elected in 2009. Executive Vice President, Chief Financial Officer, and Treasurer since April 2009. Previously served as Vice President of Internal Auditing at SCS from April 2008 to March 2009 and Vice President and Chief Financial Officer of Gulf Power from July 2001 to March 2008.

Joseph A. Miller
Executive Vice President
Age 50
Elected in 2009. Executive Vice President of Nuclear Development since May 2009. He also serves as Executive Vice President of Nuclear Development at Southern Nuclear since February 2006.

Anthony L. Wilson
Executive Vice President
Age 47
Elected in 2011. Executive Vice President of Customer Service and Operations since January 1, 2012. Previously served as Vice President of Transmission from November 2009 to December 2011 and Vice President of Distribution from February 2007 to November 2009.

Thomas P. Bishop
Senior Vice President, Chief Compliance Officer, General Counsel, and Corporate Secretary
Age 51
Elected in 2008. Corporate Secretary since April 2011 and Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008. Previously served as Vice President and Associate General Counsel for SCS from July 2004 to September 2008.

Stan W. Connally
Senior Vice President and Chief Production Officer
Age 42
Elected in 2010. Senior Vice President and Chief Production Officer since August 1, 2010. Previously served as Manager of Alabama Power’s Plant Barry from August 2007 through July 2010 and Manager of Mississippi Power’s Plant Daniel from November 2004 through August 2007.

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The officers of Georgia Power were elected for a term running from the meeting of the directors held on May 18, 2011 for one year or until their successors are elected and have qualified, except for Mr. Wilson, whose election was effective January 1, 2012.

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EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2011.

Edward Day, VI
President, Chief Executive Officer, and Director
Age 51
Elected in 2010. President, Chief Executive Officer, and Director since August 13, 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 12, 2010.

Thomas O. Anderson, IV
Vice President
Age 52
Elected in 2009. Vice President of Generation Development since July 2009. Previously served as Project Director, Mississippi Power Generation Development from March 2008 to July 2009; Project Manager, Southern Power Generation from June 2007 to March 2008; and Generation Development Manager, SCS Generation Development from September 1998 to June 2007.

John W. Atherton
Vice President
Age 51
Elected in 2004. Vice President of External Affairs since January 2005.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 47
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 13, 2010. Previously served as Vice President and Comptroller of Alabama Power from May 2008 to August 12, 2010, and Comptroller of Mississippi Power from March 2005 to May 2008.

Jeff G. Franklin
Vice President
Age 44
Elected in 2011. Vice President of Customer Services Organization since August 1, 2011. Previously served as Georgia Power's Vice President of Governmental and Legislative Affairs from January 2011 to July 2011, Vice President of Governmental and Regulatory Affairs from March 2009 to January 2011, Vice President of Sales from July 2008 to April 2009, and Vice President of the Northwest region from February 2005 to June 2008.

R. Allen Reaves
Vice President
Age 52
Elected in 2010. Vice President and Senior Production Officer since August 1, 2010. Previously served as Manager of Mississippi Power's Plant Daniel from September 2007 through July 2010 and Site Manager for Southern Power's Plant Franklin from March 2006 to September 2007.

The officers of Mississippi Power were elected for a term running from the meeting of the directors held on April 27, 2011 for one year or until their successors are elected and have qualified, except for Mr. Franklin, whose election was effective August 1, 2011.

PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low
2011		
First Quarter	$38.79	$36.51
Second Quarter	40.87	37.43
Third Quarter	43.09	35.73
Fourth Quarter	46.69	41.00
2010		
First Quarter	$33.73	$30.85
Second Quarter	35.45	32.04
Third Quarter	37.73	33.00
Fourth Quarter	38.62	37.10

There is no market for the other registrants' common stock, all of which is owned by Southern Company.

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2012: 154,700

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2011	2010
		(in thousands)	
Southern Company	First	$385,010	$359,144
	Second	402,165	375,865
	Third	405,879	378,939
	Fourth	408,294	382,440
Alabama Power	First	138,275	135,675
	Second	138,275	135,675
	Third	138,275	135,675
	Fourth	359,275	178,675
Georgia Power	First	224,025	205,000
	Second	224,025	205,000
	Third	224,025	205,000
	Fourth	424,025	205,000
Gulf Power	First	27,500	26,075
	Second	27,500	26,075
	Third	27,500	26,075
	Fourth	27,500	26,075
Mississippi Power	First	18,875	17,150
	Second	18,875	17,150
	Third	18,875	17,150
	Fourth	18,875	17,150

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In 2011 and 2010, Southern Power paid dividends to Southern Company as follows:

Registrant	Quarter	2011	2010
		(in thousands)	
Southern Power	First	$22,800	$26,775
	Second	22,800	26,775
	Third	22,800	26,775
	Fourth	22,800	26,775

The dividend paid per share of Southern Company's common stock was 45.50¢ for the first quarter 2011 and 47.25¢ each for the second, third, and fourth quarters of 2011. In 2010, Southern Company paid a dividend per share of 43.75¢ for the first quarter and 45.50¢ each for the second, third, and fourth quarters.

The traditional operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Southern Power's senior note indenture contains potential limitations on the payment of common stock dividends. At December 31, 2011, Southern Power was in compliance with the conditions of this senior note indenture and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restrictions" in Item 8 herein for additional information regarding these restrictions.

(a)(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Southern Company. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at pages II-110 and II-111.

Alabama Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-188 and II-189.

Georgia Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-272 and II-273.

Gulf Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-343 and II-344.

Mississippi Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-427 and II-428.

Southern Power. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at page II-478.

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Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Southern Company. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-11 through II-45.

Alabama Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-115 through II-139.

Georgia Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-193 through II-221.

Gulf Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-277 through II-301.

Mississippi Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-348 through II-376.

Southern Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-432 through II-452.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 10 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 9 to the financial statements of Gulf Power and Mississippi Power, and Note 8 to the financial statements of Southern Power in Item 8 herein.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

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Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this annual report, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-9 of this Form 10-K.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-113 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-191 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-275 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-346 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-430 of this Form 10-K.

(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's internal control over financial reporting is included on page II-10 of this Form 10-K.

Not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power because these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal controls.

There have been no changes in Southern Company's and Georgia Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2011 that have materially affected or are reasonably likely to materially affect Southern Company's and Georgia Power's internal control over financial reporting, other than as described in the next sentence. In October 2011, Georgia Power implemented new accounts payable, supply chain, and work management systems. The implementation of these systems provides additional operational and internal control benefits including system security and automation of previously manual controls. These process improvement initiatives were not in response to an identified internal control deficiency.

There have been no changes in Alabama Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2011 that have materially affected or are reasonably likely to materially affect Alabama Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

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THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2011 Annual Report

The management of The Southern Company ("Southern Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2011.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2011. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

/s/ Thomas A. Fanning
Thomas A. Fanning
Chairman, President, and Chief Executive Officer

/s/ Art P. Beattie
Art P. Beattie
Executive Vice President and Chief Financial Officer

February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and the financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-9). Our responsibility is to express an opinion on these financial statements and the financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements (pages II-46 to II-108) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission .

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 24, 2012

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Southern Company and Subsidiary Companies 2011 Annual Report

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional operating companies — Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) — and Southern Power Company (Southern Power), and other direct and indirect subsidiaries (together, the Southern Company system). The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants, including renewable energy projects, and by entering into power purchase agreements (PPAs) with investor-owned utilities, independent power producers, municipalities, and electric cooperatives.

Southern Company's other business activities include investments in leveraged lease projects and telecommunications. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than four million customers, Southern Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share (EPS). Southern Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2011 Peak Season EFOR of 1.28%, excluding the impact of tornadoes in April 2011, was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2011 was better than the target for these reliability measures.

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Southern Company's 2011 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
System Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season System EFOR — fossil/hydro	**4.80% or less**	**1.28%**
Basic EPS	**\$2.48 — \$2.56**	**\$2.57**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was \$2.20 billion in 2011, an increase of \$228 million from the prior year. The increase was primarily the result of increases in Georgia Power's retail base revenues as authorized under the 2010 Alternative Rate Plan for the years 2011 through 2013 (2010 ARP) and the recovery of financing costs through the Nuclear Construction Cost Recovery (NCCR) tariff. Also contributing to the increase were increases in energy and capacity revenues at Southern Power and a reduction in operations and maintenance expenses primarily at Alabama Power. The 2011 increase was partially offset by decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, a decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power, a decrease in wholesale revenues primarily at Alabama Power, and a reduction in allowance for funds used during construction (AFUDC) equity. Net income after dividends on preferred and preference stock of subsidiaries was \$1.98 billion in 2010 and \$1.64 billion in 2009.

Basic EPS was \$2.57 in 2011, \$2.37 in 2010, and \$2.07 in 2009. Diluted EPS, which factors in additional shares related to stock-based compensation, was \$2.55 in 2011, \$2.36 in 2010, and \$2.06 in 2009. EPS for 2011 was negatively impacted by \$0.08 per share as a result of an increase in the average shares outstanding.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were \$1.8725 in 2011, \$1.8025 in 2010, and \$1.7325 in 2009. In January 2012, Southern Company declared a quarterly dividend of 47.25 cents per share. This is the 257th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 70% of net income. For 2011, the actual payout ratio was 73%.

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RESULTS OF OPERATIONS

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers in the Southeast.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Electric operating revenues	**$ 17,587**	**$ 213**	$ 1,732
Fuel	**6,262**	**(437)**	747
Purchased power	**608**	**45**	89
Other operations and maintenance	**3,842**	**(63)**	505
Depreciation and amortization	**1,700**	**205**	19
Taxes other than income taxes	**899**	**32**	51
Total electric operating expenses	**13,311**	**(218)**	1,411
Operating income	**4,276**	**431**	321
Other income (expense), net	**99**	**(59)**	(40)
Interest expense, net of amounts capitalized	**803**	**(30)**	(1)
Income taxes	**1,293**	**179**	126
Net income	**2,279**	**223**	156
Dividends on preferred and preference stock of subsidiaries	**65**	**—**	—
Net income after dividends on preferred and preference stock of subsidiaries	**$ 2,214**	**$ 223**	$ 156

Electric Operating Revenues

Details of electric operating revenues were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail — prior year	**$14,791**	$13,307
Estimated change in —		
Rates and pricing	**793**	384
Sales growth (decline)	**38**	32
Weather	**(279)**	439
Fuel and other cost recovery	**(272)**	629
Retail — current year	**15,071**	14,791
Wholesale revenues	**1,905**	1,994
Other electric operating revenues	**611**	589
Electric operating revenues	**$17,587**	$17,374
Percent change	**1.2%**	11.1%

Retail revenues increased $280 million and $1.5 billion in 2011 and 2010, respectively. The significant factors driving these changes are shown in the preceding table. The increase in rates and pricing in 2011 was primarily due to increases in Georgia Power's retail base revenues as authorized under the 2010 ARP, which became effective January 1, 2011. The increase in base revenues at Georgia Power also includes the collection of financing costs associated with the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) through the NCCR tariff effective January 1, 2011. See "Other Income (Expense), Net" and "Interest Expense, Net of Amounts Capitalized" herein for additional information. Also contributing to the increase in rates and pricing in 2011 were revenues associated with Alabama Power's rate certificated new plant environmental (Rate CNP Environmental) due to the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under Alabama Power's rate structure. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Alabama Power — Retail Rate Adjustments" and "PSC Matters — Georgia Power — Rate Plans" herein for additional information. The 2010 increase in rates and pricing was primarily due to revenues associated with increases in rates under Alabama Power's stabilization and equalization plan (Rate RSE) and Rate CNP Environmental and the recovery of environmental costs at Gulf Power. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

In 2011, wholesale revenues decreased $89 million due to decreased energy revenues. This decrease was primarily due to a decrease in wholesale revenues at Alabama Power due to the expiration of long-term unit power sales contracts in May 2010 and the capacity subject to those contracts being made available for retail service starting in June 2010, as well as lower energy and capacity revenues associated with the expiration of PPAs at Southern Power. The decrease was partially offset by higher energy and capacity revenues under new PPAs at Southern Power. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Alabama Power — Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010.

In 2010, wholesale revenues increased $192 million primarily due to higher capacity and energy revenues under existing PPAs and new PPAs at Southern Power, as well as increased energy sales that were not covered by PPAs at Southern Power due to more favorable weather. This increase was partially offset by the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010.

Revenues associated with PPAs and opportunity sales were as follows:

	2011	2010	2009
		(in millions)	
Other power sales —			
Capacity and other	**$ 767**	$ 684	$ 575
Energy	**1,035**	1,034	735
Total	**$ 1,802**	$ 1,718	$ 1,310

Kilowatt-hour (KWH) sales under unit power sales contracts decreased 69.6% and 55.0% in 2011 and 2010, respectively. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010, which resulted in a decrease in capacity and energy revenues. In addition, fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales contracts, influence changes in energy sales. However, because the energy is generally sold at variable cost, fluctuations in energy sales have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2011	2010	2009
		(in millions)	
Unit power sales —			
Capacity	**$ 53**	$136	$225
Energy	**50**	140	267
Total	**$103**	$276	$492

Other Electric Revenues

Other electric revenues increased $22 million and $56 million in 2011 and 2010, respectively. Other electric revenues increased in 2011 primarily as a result of an increase in transmission revenues at Georgia Power. The 2010 increase in other electric revenues was primarily the result of a $38 million increase in transmission revenues, a $4 million increase in rents from electric property, a $4 million increase in outdoor lighting revenues, and a $4 million increase in late fees.

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Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2011 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in billions)				
Residential	**53.3**	**(7.7)%**	11.8%	**0.0%**	0.2%
Commercial	**53.9**	**(2.9)**	3.7	**(0.3)**	(0.6)
Industrial	**51.6**	**3.2**	7.7	**3.3**	7.1
Other	**0.9**	**(0.8)**	(1.0)	**(0.7)**	(1.5)
Total retail	**159.7**	**(2.7)**	7.6	**1.0%**	2.0%
Wholesale	**30.3**	**(6.8)**	(2.8)		
Total energy sales	**190.0**	**(3.4)%**	5.7%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 4.5 billion KWHs in 2011. This decrease was primarily the result of closer to normal weather in 2011 compared to 2010, partially offset by an increase in industrial KWH sales. Increased demand in the primary metals and fabricated metals sectors was the main contributor to the increase in industrial KWH sales. The number of customers in 2011 was flat when compared to 2010. Retail energy sales increased 11.6 billion KWHs in 2010 primarily as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010 when compared to the corresponding periods in 2009, increased industrial KWH sales, and customer growth of 0.3%. Increased demand in the primary metals, chemicals, and transportations sectors was the main contributor to the increase in industrial KWH sales.

Wholesale energy sales decreased 2.2 billion KWHs in 2011 and 0.9 billion KWHs in 2010. The decrease in wholesale energy sales in 2011 was primarily related to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. This decrease was partially offset by increased energy sales under new PPAs at Southern Power. The decrease in wholesale energy sales in 2010 was primarily related to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. This decrease was partially offset by increased energy sales under existing PPAs and new PPAs at Southern Power, as well as sales that were not covered by PPAs at Southern Power primarily due to more favorable weather in 2010 compared to 2009. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the electric utilities. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the electric utilities purchase a portion of their electricity needs from the wholesale market. Details of electricity generated and purchased by the electric utilities were as follows:

	2011	2010	2009
Total generation *(billions of KWHs)*	**186**	196	187
Total purchased power *(billions of KWHs)*	**12**	10	8
Sources of generation *(percent)* —			
Coal	**52**	58	57
Nuclear	**16**	15	16
Gas	**30**	25	23
Hydro	**2**	2	4
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**4.02**	3.93	3.70
Nuclear	**0.72**	0.63	0.55
Gas	**3.89**	4.27	4.58
Average cost of fuel, generated *(cents per net KWH)*	**3.43**	3.50	3.38
Average cost of purchased power *(cents per net KWH)* *	**6.32**	6.98	6.37

* Average cost of purchased power includes fuel purchased by the electric utilities for tolling agreements where power is generated by the provider.

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In 2011, fuel and purchased power expenses were $6.9 billion, a decrease of $392 million, or 5.4%, compared to 2010 costs. This decrease was primarily the result of a $186 million net decrease in the amount of total KWHs generated and purchased and a $206 million decrease in the average cost per KWH generated and purchased. The net decrease in total amount of KWHs generated and purchased was mainly the result of lower demand primarily due to closer to normal weather in 2011 compared to 2010. The decrease in the average cost per KWH generated and purchased was primarily the result of an 8.9% decrease in the average cost per gas KWH generated and a 9.5% decrease in the average cost per KWH purchased.

In 2010, fuel and purchased power expenses were $7.3 billion, an increase of $836 million, or 13.0%, compared to 2009 costs. This increase was primarily the result of a $538 million increase in the amount of total KWHs generated and purchased due primarily to increased customer demand. Also contributing to this increase was a $298 million increase in the average cost per KWH generated and purchased due primarily to a 3.6% increase in the cost per KWH generated and a 9.6% increase in the cost per KWH purchased.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011. In early 2011, uranium prices continued the steady increase started during the second half of 2010. In March 2011, uranium prices fell sharply from the highs earlier in the year. After some price volatility in the second quarter 2011, the price leveled and remained relatively constant for the remainder of 2011. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2011; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the traditional operating companies' fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" herein for additional information. Likewise, Southern Power's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $3.8 billion and $3.9 billion, decreasing $63 million and increasing $505 million in 2011 and 2010, respectively. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants increased $2 million and $277 million in 2011 and 2010, respectively. Production expenses fluctuate from year to year due to variations in outage schedules and changes in the cost of labor and materials. Other production expenses increased in 2011 mainly due to a $29 million increase in commodity and labor costs and a $26 million increase in outage and maintenance costs. This increase was largely offset by a decrease in nuclear outage expense at Alabama Power, primarily related to a change to the nuclear maintenance outage accounting process associated with the routine refueling activities, as approved by the Alabama Public Service Commission (PSC) in August 2010. As a result, Alabama Power did not recognize any nuclear maintenance outage expenses in 2011, reducing nuclear production expense by approximately $50 million as compared to 2010. See FUTURE EARNINGS POTENTIAL — "PSC Matters – Alabama Power – Nuclear Outage Accounting Order" herein for additional information. Other production expenses increased in 2010 mainly due to a $178 million increase in outage and maintenance costs and an $86 million increase in commodity and labor costs, reflecting a return to more normal spending levels when compared to 2009. Also contributing to this increase was an $18 million increase in maintenance costs related to additional equipment placed in service. Partially offsetting the 2010 increase was a $5 million loss recognized in 2009 on the transfer of Southern Power's Plant Desoto.

Transmission and distribution expenses decreased $80 million in 2011 and increased $143 million in 2010. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules and normal changes in the cost of labor and materials. Transmission and distribution expenses decreased in 2011 primarily due to reductions in spending related to vegetation management and a reduction in accruals to the natural disaster reserve (NDR) at Alabama Power. Transmission and distribution expenses increased in 2010 primarily due to increased spending related to vegetation management and other maintenance costs, reflecting a return to more normal spending levels, as well as an additional accrual to Alabama Power's NDR. See FUTURE EARNINGS POTENTIAL — "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2011 Annual Report

Customer sales and service expenses increased $33 million and $18 million in 2011 and 2010, respectively. Customer sales and service expenses increased in 2011 primarily due to a $24 million increase in customer service expense primarily related to new demand side management programs at Georgia Power and a $9 million increase in records and collection expense. Customer sales and service expenses increased in 2010 primarily as a result of an $8 million increase in sales expenses, a $13 million increase in customer service expense, a $10 million increase in records and collection expense, and a $3 million increase in uncollectible accounts expense. Partially offsetting this increase was a $7 million decrease in meter reading expenses and a $9 million decrease in other energy services.

Administrative and general expenses decreased $18 million in 2011 and increased $67 million in 2010. Administrative and general expenses decreased in 2011 primarily as a result of a $10 million decrease in property insurance cost and a $7 million decrease in injuries and damages reserve costs. Administrative and general expenses increased in 2010 primarily as a result of cost containment activities in 2009 which were taken to offset the effects of the recessionary economy.

Depreciation and Amortization

Depreciation and amortization increased $205 million in 2011 primarily as a result of a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC and additional depreciation on plant in service related to environmental, transmission, and distribution projects. See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power– Rate Plans" for additional information regarding Georgia Power's cost of removal amortization.

Depreciation and amortization increased $19 million in 2010 primarily as the result of additional depreciation on plant in service related to environmental, transmission, and distribution projects, as well as additional depreciation at Southern Power. This increase was largely offset by a $133 million increase in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $32 million in 2011 primarily due to increases in property taxes and municipal franchise fees at Georgia Power and increases in state and municipal public utility license tax bases at Alabama Power. Taxes other than income taxes increased $51 million in 2010 primarily due to increases in municipal franchise fees at Georgia Power, increases in state and municipal public utility license tax bases at Alabama Power, increases in gross receipts and franchise fees at Gulf Power, increases in ad valorem taxes, and increases in payroll taxes. Increases in franchise fees are associated with increases in revenues from energy sales.

Other Income (Expense), Net

Other income (expense), net decreased $59 million in 2011 primarily due to the inclusion of Georgia Power's construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized, with an offsetting increase in operating revenues through the NCCR tariff. Also contributing to the decrease was reduced AFUDC equity at Alabama Power due to the completion of construction projects related to environmental mandates and a $20 million loss at Southern Power related to a make-whole premium in connection with the early redemption of senior notes. The 2011 decrease was partially offset by construction work in progress related to Mississippi Power's Kemper County integrated coal gasification combined cycle (Kemper IGCC) which began construction in June 2010. Other income (expense), net decreased $40 million in 2010 primarily due to a decrease in AFUDC equity, mainly due to the completion of environmental projects at Alabama Power and Gulf Power, and a $13 million profit recognized in 2009 at Southern Power related to a construction contract with the Orlando Utilities Commission. The 2010 decrease was partially offset by increases in AFUDC equity related to the increase in construction of three new combined cycle units and Plant Vogtle Units 3 and 4 at Georgia Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

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Interest Expense, Net of Amounts Capitalized

Total interest charges and other financing costs decreased $30 million in 2011 primarily due to a reduction of $23 million in interest expense at Georgia Power related to the settlement of litigation with the Georgia Department of Revenue (DOR) and lower interest expense on existing variable rate pollution control revenue bonds at Georgia Power. The decrease was partially offset by a reduction in AFUDC debt at Georgia Power due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base.

Total interest charges and other financing costs decreased $1 million in 2010 primarily due to an $18 million decrease related to lower average interest rates on existing variable rate debt, an $11 million decrease in other interest costs, and a $2 million increase in capitalized interest as compared to 2009. The 2010 decrease was largely offset by a $29 million increase associated with $1.0 billion in additional debt outstanding at December 31, 2010 compared to December 31, 2009.

Income Taxes

Income taxes increased $179 million in 2011 primarily due to higher pre-tax earnings as compared to 2010, a decrease in 2010 in uncertain tax positions at Georgia Power related to state income tax credits, and a reduction in AFUDC equity, which is non-taxable.

Income taxes increased $126 million in 2010 primarily due to higher pre-tax earnings as compared to 2009, a decrease in the Internal Revenue Code of 1986, as amended, Section 199 production activities deduction, and an increase in Alabama state taxes due to a decrease in the state deduction for federal income taxes paid. Partially offsetting this increase were state tax credits at Georgia Power and tax benefits associated with the construction of a biomass facility at Southern Power. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease projects, and telecommunications. These businesses are classified in general categories and may comprise one or both of the following subsidiaries: Southern Company Holdings, Inc. invests in various projects, including leveraged lease projects, and SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

A condensed statement of income for Southern Company's other business activities follows:

	Amount	**Increase (Decrease) from Prior Year**	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$ 70**	**$ (12)**	$ (19)
Other operations and maintenance	**96**	**(9)**	(21)
MC Asset Recovery litigation settlement	**—**	**—**	(202)
Depreciation and amortization	**17**	**(1)**	(9)
Taxes other than income taxes	**2**	**—**	—
Total operating expenses	**115**	**(10)**	(232)
Operating income (loss)	**(45)**	**(2)**	213
Equity in income (losses) of unconsolidated subsidiaries	**(2)**	**—**	(1)
Leveraged lease income (losses)	**25**	**7**	(22)
Other income (expense), net	**(9)**	**6**	(19)
Interest expense	**54**	**(8)**	(9)
Income taxes	**(74)**	**14**	4
Net income (loss)	**$ (11)**	**$ 5**	$176

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Operating Revenues

Southern Company's non-electric operating revenues from these other business activities decreased $12 million in 2011 primarily as a result of a decrease in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry. The $19 million decrease in 2010 primarily resulted from a decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other businesses decreased $9 million in 2011 and $21 million in 2010. These decreases were primarily the result of lower administrative and general expenses for these other businesses.

MC Asset Recovery Litigation Settlement

In March 2009, Southern Company entered into a litigation settlement agreement with MC Asset Recovery, LLC (MC Asset Recovery) which resulted in a charge of $202 million and required MC Asset Recovery to release Southern Company and certain other designated avoidance actions assigned to MC Asset Recovery in connection with Mirant Corporation's plan of reorganization, as well as to release all actions against current or former officers and directors of Mirant Corporation and Southern Company that had or could have been filed. Pursuant to the settlement, Southern Company recorded a charge in the first quarter 2009 of $202 million, which was paid in the second quarter 2009. The settlement has been completed and resolves all claims by MC Asset Recovery against Southern Company. In June 2009, the case was dismissed with prejudice.

Leveraged Lease Income (Losses)

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Leveraged lease income (losses) increased $7 million in 2011 primarily as a result of changes in the average leveraged lease investment balance. Leveraged lease income (losses) decreased $22 million in 2010 primarily as a result of a $26 million gain recorded in 2009 associated with the early termination of two international leveraged lease investments, the proceeds from which were required to extinguish all debt related to the leveraged lease investments, and a portion of which had make-whole redemption provisions. This resulted in a $17 million loss in 2009, partially offsetting the gain. In addition, leveraged lease income decreased $6 million in 2010 primarily due to lease income no longer being recognized on the terminated leveraged lease investments.

Other Income (Expense), Net

Other income (expense), net for these other businesses increased $6 million in 2011 and decreased $19 million in 2010 primarily as a result of changes in the amount of charitable contributions made by the parent company in 2011 and 2010.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $8 million in 2011 and $9 million in 2010 primarily due to lower average interest rates on existing variable rate debt in the applicable period.

Income Taxes

Income taxes for these other businesses increased $14 million in 2011 primarily as a result of lower pre-tax losses and a prior year state tax adjustment related to leveraged leases. The 2010 increase in income taxes was not material when compared to the prior year.

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Effects of Inflation

The traditional operating companies are subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC). Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Another major factor is the profitability of the competitive wholesale supply business. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service area. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available, cost, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in economic conditions impact sales for the traditional operating companies and Southern Power, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

In general, the Southern Company system has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of the Southern Company system's regulated retail markets, both of which are optimized by limited energy trading activities. See "Construction Program" herein and Note 7 to the financial statements for additional information.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

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New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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Environmental Statutes and Regulations

General

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the traditional operating companies had invested approximately $8.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $300 million, $500 million, and $1.3 billion for 2011, 2010, and 2009, respectively. The Southern Company system expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $1.5 billion from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$ 425	$ 405	$ 621

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $750 million as described below.

The Southern Company system is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Southern Company system estimates that the aggregate capital costs to the traditional operating companies for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $13 billion to $18 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $750 million that is also included in the 2012 through 2014 base level capital investment of the traditional operating companies described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Southern Company system's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $2.7 billion from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $1.5 billion over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	Up to $ 370	Up to $770	Up to $1,610
Proposed water and coal combustion byproducts rules	Up to $40	Up to $365	Up to $1,090
Total potential incremental environmental compliance investments	**Up to $410**	**Up to $1,135**	**Up to $ 2,700**

The Southern Company system's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Southern Company system's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

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As of December 31, 2011, the Southern Company system had total generating capacity of approximately 43,555 megawatts (MWs), of which 20,212 MWs are coal-fired. Over the past several years, the Southern Company system has installed various pollution control technologies on coal-fired units, including both selective catalytic reduction equipment and scrubbers on the 17 largest coal units making up 11,036 MWs of the Southern Company system's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Southern Company system is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including on the units with existing pollution control technologies), and changing fuel sources for certain units.

Southern Electric Generating Company (SEGCO), jointly owned by Alabama Power and Georgia Power, is also developing an environmental compliance strategy for its 1,000 MWs of coal-fired generating capacity, which may result in unit retirements, installation of controls, or changing fuel source. The capacity of SEGCO's units is sold to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on Southern Company's financial statements. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Since 1990, the electric utilities spent approximately $7.4 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. The 2008 standard is expected to result in designation of new nonattainment areas within the Southern Company system service territory and could require additional reductions in NO_x emissions.

The EPA also regulates fine particulate matter emissions on an annual and 24-hour average basis. Although all areas within the Southern Company system's service territory have air quality levels that attain the current standard, the EPA has announced its intention to propose new, more stringent annual and 24-hour fine particulate matter standards in mid-2012.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Southern Company system's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Southern Company system's service territory were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

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In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. On April 6, 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by Alabama Power, including units co-owned by Mississippi Power. Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves Alabama Power's appeal in its favor, the EPA's rescission will continue to affect Alabama Power's operations.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the traditional operating companies and Southern Power) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the states of Florida, Georgia, and Mississippi.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the facilities of Southern Company's subsidiaries which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

On March 21, 2011, the EPA published the final Industrial Boiler (IB) Maximum Achievable Control Technology (MACT) rule establishing emissions limits for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. At the same time, the EPA issued a notice of intent to reconsider the final rule and, on May 16, 2011, the EPA issued an administrative stay to prevent the rule from becoming effective. On December 2, 2011, the EPA proposed a reconsideration rule to change certain aspects of the final rule. On January 9, 2012, however, the U.S. District Court for the District of Columbia Circuit vacated the EPA's administrative stay. Although the U.S. District Court for the District of Columbia Circuit's decision would allow the original IB MACT rule to become effective, the EPA has indicated that it will not implement the rule until the EPA's proposed revisions can be finalized. The effect of the regulatory proceedings will depend on the final form of the revised regulations and the outcome of any legal challenges and cannot be determined at this time. On October 18, 2011, the Georgia PSC approved Georgia Power's request to further delay the decision to convert Plant Mitchell Unit 3 from coal to biomass for two to four years, until there is greater clarity regarding the IB MACT rule and other proposed and recently adopted regulations.

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The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, the MATS rule, and the IB MACT rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In addition to the federal air quality laws described above, Georgia Power is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2011, Georgia Power had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. As a result of uncertainties related to the potential federal air quality regulations described above, Georgia Power has suspended certain work related to the installation of emissions control equipment at Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7. Georgia Power continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. Georgia Power may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls. See "PSC Matters – Georgia Power – 2011 Integrated Resource Plan Update" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the traditional operating companies' generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the facilities of Southern Company's subsidiaries may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions.

Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Southern Company system facilities, which could result in significant additional capital expenditures and compliance costs, as described above, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The traditional operating companies currently operate 22 electric generating plants with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the traditional operating companies also sell a portion of their coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the states in the Southern Company system's service territory each have their own regulatory parameters. Each traditional operating company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

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The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described above, that could affect future unit retirement and replacement decisions. Moreover, the traditional operating companies could incur additional material asset retirement obligations with respect to closing existing storage facilities. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Environmental Remediation

The Southern Company system must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies conduct studies to determine the extent of any required cleanup and have recognized in their respective financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs. The traditional operating companies may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters — Environmental Remediation" for additional information.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

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International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Southern Company system's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Southern Company system's 2010 greenhouse gas emissions were approximately 137 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Southern Company system's 2011 greenhouse gas emissions on the same basis is approximately 125 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Southern Company system is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. These include, but are not limited to: new nuclear generation, including Plant Vogtle Units 3 and 4; construction of the Kemper IGCC with approximately 65% carbon capture; and renewable investments, including the construction of a biomass plant in Sacul, Texas and Alabama Power's purchase of approximately 400 MWs of energy from renewable sources, including wind energy (some of which remains subject to regulatory approval). In addition, Southern Power completed construction on a solar photovoltaic plant near Cimarron, New Mexico in 2010. The Southern Company system is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies.

PSC Matters

Alabama Power

Retail Rate Adjustments

On July 12, 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information.

Rate RSE

Alabama Power operates under Rate RSE approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

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In 2011, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, Alabama Power agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, Alabama Power had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that Alabama Power leave in effect for 2012 the factors associated with Alabama Power's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, Alabama Power had an under recovered environmental clause balance of $11 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. On September 7, 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations – General" herein for additional information regarding environmental regulations.

Natural Disaster Reserve

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Alabama Power has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

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In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows Alabama Power to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred on April 27, 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC on July 12, 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balance in the NDR for the year ended December 31, 2011 was approximately $110 million.

For the year ended December 31, 2010, Alabama Power accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

In August 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In December 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors.

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Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been or will be made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Other Construction" below for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, Georgia Power's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2010 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

2011 Integrated Resource Plan Update

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," " – Water Quality," and " – Coal Combustion Byproducts" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the 2010 ARP.

On August 4, 2011, Georgia Power filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included Georgia Power's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. Georgia Power also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, Georgia Power is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 MWs of capacity. Georgia Power is currently updating its economic analysis of these units based on the final MATS rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, Georgia Power cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes Georgia Power's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process.

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In addition, Georgia Power filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, Georgia Power entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated Integrated Resource Plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decision, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Southern Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. In previous years, the traditional operating companies experienced volatility in pricing of fuel commodities with higher than expected pricing for coal and uranium and volatile price swings in natural gas. This volatility and higher fuel costs have resulted in total under recovered fuel costs included in the balance sheets of Alabama Power and Georgia Power of approximately $169 million at December 31, 2011. Gulf Power and Mississippi Power collected all previously under recovered fuel costs and, as of December 31, 2011, had a total over recovered fuel balance of approximately $52 million. At December 31, 2010, total under recovered fuel costs included in the balance sheets of Alabama Power, Georgia Power, and Gulf Power were approximately $420 million, and Mississippi Power had a total over recovered fuel balance of approximately $55 million. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect annual cash flow. The traditional operating companies continuously monitor the under or over recovered fuel cost balances.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery," for additional information.

Income Tax Matters

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. In 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, Georgia Power and the Georgia DOR agreed to a settlement resolving the claims. As a result, Georgia Power recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, Georgia Power recorded a reduction of approximately $23 million in related interest expense. See Note 3 under "Retail Regulatory Matters – Georgia Power – Other Construction" and "Income Tax Matters – Georgia State Income Tax Credits" for additional information on this regulatory liability.

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Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Company through 2013. Due to the significant amount of estimated bonus depreciation for 2012, tax credit utilization will be reduced. Consequently, it is estimated there will be a positive cash flow benefit of between $400 million and $550 million in 2012.

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. Southern Company intends to continue its strategy of developing and constructing new generating facilities, including natural gas and biomass units at Southern Power, natural gas units and Plant Vogtle Units 3 and 4 at Georgia Power, and the Kemper IGCC at Mississippi Power, as well as adding environmental control equipment and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. See Note 7 to the financial statements under "Construction Program" for estimated construction expenditures for the next three years. In addition, see Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Integrated Coal Gasification Combined Cycle" for additional information.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

Investments in Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the asset. Southern Company will continue to monitor the performance of the underlying assets and to evaluate the ability of the lessee to continue to make the required lease payments. While there are strategic options that Southern Company may pursue to recover its investment in the leveraged lease, the potential impairment loss that would be incurred if there is an abandonment of the project is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent.

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the Nuclear Regulatory Commission (NRC) is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time. See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 96% of Southern Company's total operating revenues for 2011, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

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Contingent Obligations

Southern Company and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject them to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's financial statements.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Alabama Power is able to determine a significant amount of metered unbilled KWH sales due to the installation of automated meters. At the end of each month, amounts of electricity delivered are read for the customers with automated meters. From this reading, unbilled KWH sales are determined and included in Alabama Power's unbilled revenue calculation. Estimates of unbilled electricity delivered are made when automated meter readings are not available.

Pension and Other Postretirement Benefits

Southern Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining Southern Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. Southern Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

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The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the assumed discount rate, the assumed salaries, and the assumed long-term rate of return on plan assets:

Change in Assumption	Increase/(Decrease) in Total Benefit Expense for 2012	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2011	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2011
		(in millions)	
25 basis point change in discount rate	$28/$(26)	$287/$(272)	$54/$(51)
25 basis point change in salaries	$14/$(14)	$73/$(70)	$-/$-
25 basis point change in long-term return on plan assets	$20/$(20)	N/A	N/A

N/A – Not applicable

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2011. Southern Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2012 through 2014, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. Southern Company does not expect any material changes to funding obligations to the nuclear decommissioning trust funds prior to 2014.

Net cash provided from operating activities in 2011 totaled $5.9 billion, an increase of $1.9 billion from the corresponding period in 2010. Significant changes in operating cash flow for 2011 as compared to the corresponding period in 2010 include an increase in net income, a contribution to the qualified pension plan in 2010, and a decrease in taxes paid due to bonus depreciation. Net cash provided from operating activities in 2010 totaled $4 billion, an increase of $728 million from the corresponding period in 2009. Significant changes in operating cash flow for 2010 as compared to the corresponding period in 2009 include an increase in net income, a reduction in fossil fuel stock, and an increase in deferred income taxes primarily due to the change in the tax accounting method for repair costs. A contribution to the qualified pension plan partially offset these increases.

Net cash used for investing activities in 2011 totaled $4.2 billion primarily due to property additions to utility plant. Net cash used for investing activities in 2010 totaled $4.3 billion primarily due to property additions to utility plant. Net cash used for investing activities in 2009 totaled $4.3 billion primarily due to property additions to utility plant of $4.7 billion, partially offset by approximately $340 million in cash received from the early termination of two leveraged lease investments.

Net cash used for financing activities totaled $852 million in 2011, compared to $22 million net cash provided from financing activities in 2010. This change was primarily due to a reduction of short-term debt outstanding and redemptions of long-term debt in 2011. Net cash provided from financing activities totaled $22 million in 2010, a decrease of $1.3 billion from the corresponding period in 2009. This decrease was primarily due to redemptions of long-term debt in 2010.

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Significant balance sheet changes in 2011 include an increase of $3.0 billion in total property, plant, and equipment for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities. Other significant changes include an increase in cash of $868 million due to increased cash collection from operations, an increase in deferred income taxes of $1.3 billion due to bonus depreciation and a change in the tax accounting method for repair costs, and $1.4 billion of additional equity.

At the end of 2011, the closing price of Southern Company's common stock was $46.29 per share, compared with a book value of $20.32 per share. The market-to-book value ratio was 228% at the end of 2011, compared with 199% at year-end 2010.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2012, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described below with respect to potential U.S. Department of Energy (DOE) loan guarantees, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

In June 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for Georgia Power.

In addition, Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees for Mississippi Power. Mississippi Power also received DOE Clean Coal Power Initiative Round 2 grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for the initial operation of the Kemper IGCC.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

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At December 31, 2011, Southern Company and its subsidiaries had approximately $1.3 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

	Expires (a)						Due Within One Year		Executable Term-Loans	
Company	2012	2013	2014	2016	Total	Unused	Term Out	No Term Out	One Year	Two Years
	(in millions)				(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$—	$ —	$1,000	$1,000	$1,000	$ —	$ —	$ —	$—
Alabama Power	121	35	350	800	1,306	1,306	51	71	51	—
Georgia Power	—	—	250	1,500	1,750	1,745	—	—	—	—
Gulf Power	75	—	165	—	240	240	75	—	75	—
Mississippi Power	131	—	165	—	296	296	66	65	25	41
Southern Power	—	—	—	500	500	500	—	—	—	—
Other	25	25	—	—	50	50	25	—	25	—
Total	$352	$60	$930	$3,800	$5,142	$5,137	$217	$136	$176	$41

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2011 was approximately $1.8 billion.

The traditional operating companies may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of each of the traditional operating companies. Details of short-term borrowings, excluding notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2011:					
Commercial paper	$654	0.28%	$697	0.29%	$1,586
Short-term bank debt	200	1.18%	14	1.21%	200
Total	$854	0.49%	$711	0.32%	
December 31, 2010:					
Commercial paper	$1,295	0.32%	$690	0.29%	$1,305

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

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Financing Activities

During 2011, Southern Company issued approximately 21.9 million shares of common stock for $723 million through the Southern Investment Plan and employee and director stock plans. The proceeds were primarily used for general corporate purposes, including the investment by Southern Company in its subsidiaries, and to repay short-term indebtedness. While Southern Company continues to issue additional equity through its employee and director equity compensation plans, Southern Company is not currently issuing additional shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by the independent plan administrators.

The following table outlines the debt financing activities for Southern Company, the traditional operating companies, and Southern Power for the year ended December 31, 2011:

Company	Senior Note Issuances	Senior Note Redemptions and Maturities	Pollution Control Bond Issuances and Remarketings (*)	Pollution Control Bond Repurchases, Redemptions, and Maturities	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities
			(in millions)			
Southern Company	$ 500	$ 300	$ —	$ —	$ —	$ —
Alabama Power	700	750	—	4	—	—
Georgia Power	550	427	604	339	250	509
Gulf Power	125	—	—	—	—	110
Mississippi Power	300	—	—	—	115	130
Southern Power	575	575	—	—	—	3
Total	$ 2,750	$ 2,052	$ 604	$ 343	$ 365	$ 752

(*) Reflects the remarketing of pollution control bonds that had been purchased and held.

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above to repay short-term indebtedness, to fund acquisitions, and for general corporate purposes, including their respective continuous construction programs.

In August 2011, Southern Company issued $500 million aggregate principal amount of Series 2011A 1.95% Senior Notes due September 1, 2016. The net proceeds from the sale of the Series 2011A Senior Notes were used to repay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

In October 2011, Southern Company's $300 million aggregate principal amount of Series 2009B Floating Rate Senior Notes matured.

In March 2011, Alabama Power settled $200 million of interest rate hedges related to its Series 2011A 5.50% Senior Note issuance at a gain of approximately $4 million. The gain is being amortized to interest expense, in earnings, over 10 years.

In August 2011, Alabama Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $300 million.

In September 2011, Mississippi Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to anticipated debt issuances. The notional amount of the swaps totaled $600 million. Mississippi Power also settled $300 million of the interest rate swaps in October 2011; $150 million related to its Series 2011A 2.35% Senior Note issuance at a gain of approximately $1.4 million which is being amortized to interest expense, in earnings, over five years; and $150 million related to its Series 2011B 4.75% Senior Note issuance at a loss of approximately $0.5 million which is being amortized to interest expense, in earnings, over 10 years.

In October 2011, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 21, 2021, issued for the benefit of the lessor as described under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by the combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4) and certain personal property.

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In November 2011, Alabama Power entered into forward-looking interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $100 million.

Subsequent to December 31, 2011, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

Subsequent to December 31, 2011, Alabama Power issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including Alabama Power's continuous construction program. In November 2011, Alabama Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes in anticipation of this debt issuance. The notional amount of the swaps totaled $100 million and settled subsequent to December 31, 2011, at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

Subsequent to December 31, 2011, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012. Also, Alabama Power announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

Subsequent to December 31, 2011, Georgia Power entered into a floating rate six-month short-term bank loan in an aggregate amount of $100 million, bearing interest based on one-month LIBOR. The proceeds were used for general corporate purposes, including Georgia Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, Mississippi Power began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. On July 20, 2011, Mississippi Power provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4.

On October 20, 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. Accordingly, Plant Daniel Units 3 and 4 are reflected in Southern Company's financial statements at approximately $431 million.

In connection with the purchase of Plant Daniel Units 3 and 4, Mississippi Power filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized Mississippi Power to defer a regulatory asset for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30 year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. On November 2, 2011, Mississippi Power filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The ultimate outcome of this matter cannot be determined at this time.

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Credit Rating Risk

Southern Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2011 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	613
Below BBB- and/or Baa3	2,812

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. The Company may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2011 have a notional amount of $1.1 billion and are related to fixed and floating rate obligations over the next several years. The weighted average interest rate on $3.7 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2012 was 0.81%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $37 million at January 1, 2012. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs.

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The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(196)**	$(178)
Contracts realized or settled	**179**	197
Current period changes [(a)]	**(214)**	(215)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(231)**	$(196)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was a decrease of $35 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, Southern Company had a net hedge volume of 189 million mmBtu with a weighted average swap contract cost approximately $1.51 per mmBtu above market prices, compared to a net hedge volume of 149 million mmBtu at December 31, 2010 with a weighted average swap contract cost approximately $1.35 per mmBtu above market prices. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**2011**	2010
	(in millions)	
Regulatory hedges	**$(221)**	$(193)
Cash flow hedges	**(1)**	(1)
Not designated	**(9)**	(2)
Total fair value	**$(231)**	$(196)

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2011, 2010, and 2009 for energy-related derivative contracts that are not hedges were $(6) million, $(2) million, and $(5) million, respectively.

Southern Company uses over-the-counter contracts that are not exchange-traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(231)	(164)	(65)	(2)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(231)	$(164)	$(65)	$(2)

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Southern Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as detailed below. Although its analyses are preliminary, Southern Company estimates that the aggregate capital costs to the traditional operating companies for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $13 billion to $18 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rules. Included in this amount is approximately $750 million that is also included in the 2012 through 2014 base level capital investment of the traditional operating companies described herein in anticipation of these rules. The Southern Company system's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$4,842	$3,976	$3,720
Existing environmental statutes and regulations	425	405	621
Total construction program base level capital investment	**$5,267**	**$4,381**	**$4,341**
Potential incremental environmental compliance investments:			
MATS rule	Up to $ 370	Up to $770	Up to $1,610
Proposed water and coal combustion byproducts rules	Up to $40	Up to $365	Up to $1,090
Total potential incremental environmental compliance investments	**Up to $410**	**Up to $1,135**	**Up to $2,700**

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Integrated Coal Gasification Combined Cycle" and Note 7 to the financial statements under "Construction Program" for additional information.

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As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt [a] —						
Principal	$ 1,693	$ 2,523	$2,443	$13,566	$ —	$20,225
Interest	865	1,532	1,379	10,679	—	14,455
Preferred and preference stock dividends [b]	65	130	130	—	—	325
Energy-related derivative obligations [c]	173	70	2	—	—	245
Interest rate derivative obligations [c]	33	—	—	—	—	33
Foreign currency derivative obligations [c]	3	—	—	—	—	3
Operating leases	121	183	75	85	—	464
Capital leases	24	28	13	28	—	93
Unrecognized tax benefits and interest [d]	25	—	—	—	105	130
Purchase commitments [e] —						
Capital [f]	4,808	7,794	—	—	—	12,602
Limestone [g]	41	84	51	70	—	246
Coal	3,266	3,554	892	737	—	8,449
Nuclear fuel	353	403	237	740	—	1,733
Natural gas [h]	1,479	2,749	1,935	2,798	—	8,961
Purchased power	259	529	612	2,700	—	4,100
Long-term service agreements [i]	123	302	349	1,141	—	1,915
Trusts —						
Nuclear decommissioning [j]	2	3	3	34	—	42
Pension and other postretirement benefit plans [k]	100	196	—	—	—	296
Total	$13,433	$20,080	$8,121	$32,578	$ 105	$74,317

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2012, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Represents preferred and preference stock of subsidiaries. Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $105 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Notes 3 and 5 to the financial statements for additional information.

(e) Southern Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2011, 2010, and 2009 were $3.9 billion, $4.0 billion, and $3.5 billion, respectively.

(f) The Southern Company system provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Southern Company system's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $410 million for 2012, up to $1.1 billion for 2013, and up to $2.7 billion for 2014. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Southern Company system's program to reduce SO_2 emissions from its coal plants, the traditional operating companies have entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for Georgia Power.

(k) The Southern Company system forecasts contributions to the pension and other postretirement benefit plans over a three-year period.

Southern Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from Southern Company’s corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from Southern Company’s corporate assets.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2011 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, future earnings, dividend payout ratios, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of Southern Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals, potential DOE loan guarantees, the South Mississippi Electric Power Association purchase decision, and utilization of investment tax credits;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

Southern Company expressly disclaims any obligation to update any forward-looking statements.

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 15,071**	$ 14,791	$ 13,307
Wholesale revenues	**1,905**	1,994	1,802
Other electric revenues	**611**	589	533
Other revenues	**70**	82	101
Total operating revenues	**17,657**	17,456	15,743
Operating Expenses:			
Fuel	**6,262**	6,699	5,952
Purchased power	**608**	563	474
Other operations and maintenance	**3,938**	4,010	3,526
MC Asset Recovery litigation settlement	**—**	—	202
Depreciation and amortization	**1,717**	1,513	1,503
Taxes other than income taxes	**901**	869	818
Total operating expenses	**13,426**	13,654	12,475
Operating Income	**4,231**	3,802	3,268
Other Income and (Expense):			
Allowance for equity funds used during construction	**153**	194	200
Interest expense, net of amounts capitalized	**(857)**	(895)	(905)
Other income (expense), net	**(40)**	(35)	41
Total other income and (expense)	**(744)**	(736)	(664)
Earnings Before Income Taxes	**3,487**	3,066	2,604
Income taxes	**1,219**	1,026	896
Consolidated Net Income	**2,268**	2,040	1,708
Dividends on Preferred and Preference Stock of Subsidiaries	**65**	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 2,203**	$ 1,975	$ 1,643
Common Stock Data:			
Earnings per share (EPS)—			
Basic EPS	**$ 2.57**	$ 2.37	$ 2.07
Diluted EPS	**2.55**	2.36	2.06
Average number of shares of common stock outstanding — (in millions)			
Basic	**857**	832	795
Diluted	**864**	837	796
Cash dividends paid per share of common stock	**$ 1.8725**	$ 1.8025	$ 1.7325

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in millions)	
Consolidated Net Income	**$ 2,268**	$ 2,040	$ 1,708
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(10), $-, and $(3), respectively	**(18)**	(1)	(4)
Reclassification adjustment for amounts included in net income, net of tax of $6, $9, and $18, respectively	**9**	15	28
Marketable securities:			
Change in fair value, net of tax of $(2), $(2), and $1, respectively	**(4)**	(3)	4
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(1), $1, and $(8), respectively	**(2)**	6	(12)
Reclassification adjustment for amounts included in net income, net of tax of $(14), $1, and $1, respectively	**(26)**	1	1
Total other comprehensive income (loss)	**(41)**	18	17
Dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Consolidated Comprehensive Income	**$ 2,162**	$ 1,993	$ 1,660

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 2,268**	$ 2,040	$ 1,708
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	**2,048**	1,831	1,788
Deferred income taxes	**1,155**	1,038	25
Deferred revenues	**(4)**	(103)	(54)
Allowance for equity funds used during construction	**(153)**	(194)	(200)
Pension, postretirement, and other employee benefits	**(45)**	(614)	(3)
Stock based compensation expense	**42**	33	23
Generation construction screening costs	**—**	(51)	(22)
Other, net	**19**	70	43
Changes in certain current assets and liabilities —			
-Receivables	**362**	80	585
-Fossil fuel stock	**(62)**	135	(432)
-Materials and supplies	**(60)**	(30)	(39)
-Other current assets	**(17)**	(17)	(47)
-Accounts payable	**(5)**	4	(125)
-Accrued taxes	**330**	(308)	(95)
-Accrued compensation	**10**	180	(226)
-Other current liabilities	**15**	(103)	334
Net cash provided from operating activities	**5,903**	3,991	3,263
Investing Activities:			
Property additions	**(4,525)**	(4,086)	(4,670)
Distribution of restricted cash	**63**	25	119
Nuclear decommissioning trust fund purchases	**(2,195)**	(2,009)	(1,234)
Nuclear decommissioning trust fund sales	**2,190**	2,004	1,228
Proceeds from property sales	**25**	18	340
Cost of removal, net of salvage	**(93)**	(125)	(119)
Change in construction payables	**191**	(51)	215
Other investing activities	**161**	(32)	(198)
Net cash used for investing activities	**(4,183)**	(4,256)	(4,319)
Financing Activities:			
Increase (decrease) in notes payable, net	**(438)**	659	(306)
Proceeds —			
Long-term debt issuances	**3,719**	3,151	3,042
Common stock issuances	**723**	772	1,286
Redemptions and repurchases —			
Long-term debt	**(3,170)**	(2,966)	(1,234)
Payment of common stock dividends	**(1,601)**	(1,496)	(1,369)
Payment of dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Other financing activities	**(20)**	(33)	(25)
Net cash provided from (used for) financing activities	**(852)**	22	1,329
Net Change in Cash and Cash Equivalents	**868**	(243)	273
Cash and Cash Equivalents at Beginning of Year	**447**	690	417
Cash and Cash Equivalents at End of Year	**$ 1,315**	$ 447	$ 690

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED BALANCE SHEETS
At December 31, 2011 and 2010
Southern Company and Subsidiary Companies 2011 Annual Report

Assets	2011	2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,315**	$ 447
Restricted cash and cash equivalents	**8**	68
Receivables —		
Customer accounts receivable	**1,074**	1,140
Unbilled revenues	**376**	420
Under recovered regulatory clause revenues	**143**	209
Other accounts and notes receivable	**282**	285
Accumulated provision for uncollectible accounts	**(26)**	(25)
Fossil fuel stock, at average cost	**1,367**	1,308
Materials and supplies, at average cost	**903**	827
Vacation pay	**160**	151
Prepaid expenses	**385**	784
Other regulatory assets, current	**239**	210
Other current assets	**46**	59
Total current assets	**6,272**	5,883
Property, Plant, and Equipment:		
In service	**59,744**	56,731
Less accumulated depreciation	**21,154**	20,174
Plant in service, net of depreciation	**38,590**	36,557
Other utility plant, net	**55**	—
Nuclear fuel, at amortized cost	**774**	670
Construction work in progress	**5,591**	4,775
Total property, plant, and equipment	**45,010**	42,002
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,207**	1,370
Leveraged leases	**649**	624
Miscellaneous property and investments	**262**	277
Total other property and investments	**2,118**	2,271
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,365**	1,280
Prepaid pension costs	**—**	88
Unamortized debt issuance expense	**156**	178
Unamortized loss on reacquired debt	**285**	274
Deferred under recovered regulatory clause revenues	**48**	218
Other regulatory assets, deferred	**3,532**	2,402
Other deferred charges and assets	**481**	436
Total deferred charges and other assets	**5,867**	4,876
Total Assets	**$59,267**	$55,032

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED BALANCE SHEETS
At December 31, 2011 and 2010
Southern Company and Subsidiary Companies 2011 Annual Report

Liabilities and Stockholders' Equity	**2011**	2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,717**	$ 1,301
Notes payable	**859**	1,297
Accounts payable	**1,553**	1,275
Customer deposits	**347**	332
Accrued taxes —		
Accrued income taxes	**13**	8
Unrecognized tax benefits	**22**	187
Other accrued taxes	**425**	440
Accrued interest	**226**	225
Accrued vacation pay	**205**	194
Accrued compensation	**450**	438
Liabilities from risk management activities	**209**	152
Other regulatory liabilities, current	**125**	88
Other current liabilities	**426**	535
Total current liabilities	**6,577**	6,472
Long-Term Debt (See accompanying statements)	**18,647**	18,154
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**8,809**	7,554
Deferred credits related to income taxes	**224**	235
Accumulated deferred investment tax credits	**611**	509
Employee benefit obligations	**2,442**	1,580
Asset retirement obligations	**1,321**	1,257
Other cost of removal obligations	**1,165**	1,158
Other regulatory liabilities, deferred	**297**	312
Other deferred credits and liabilities	**514**	517
Total deferred credits and other liabilities	**15,383**	13,122
Total Liabilities	**40,607**	37,748
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**375**	375
Total Stockholders' Equity (See accompanying statements)	**18,285**	16,909
Total Liabilities and Stockholders' Equity	**$59,267**	$55,032
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2011 and 2010
Southern Company and Subsidiary Companies 2011 Annual Report

		2011	2010	2011	2010
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Maturity	Interest Rates				
2044	5.88%	**$ —**	$ 206		
Variable rate (3.68% at 1/1/12) due 2042		**206**	206		
Total long-term debt payable to affiliated trusts		**206**	412		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2011	4.00% to 5.57%	**—**	304		
2012	4.85% to 6.25%	**1,203**	1,778		
2013	1.30% to 6.00%	**1,436**	1,436		
2014	4.15% to 4.90%	**437**	425		
2015	2.38% to 5.25%	**1,175**	1,184		
2016	1.95% to 5.30%	**1,210**	310		
2017 through 2051	2.25% to 8.20%	**9,797**	9,128		
Variable rates (0.56% to 0.78% at 1/1/11) due 2011		**—**	915		
Variable rates (0.60% to 0.95% at 1/1/12) due 2012		**490**	—		
Variable rates (0.85% to 0.90% at 1/1/12) due 2013		**650**	350		
Variable rate (0.44% at 1/1/11) due 2040		**—**	50		
Total long-term senior notes and debt		**16,398**	15,880		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2016	4.40%	**—**	67		
2018 through 2049	0.75% to 6.00%	**1,590**	1,740		
Variable rate (0.39% at 1/1/11) due 2011		**—**	8		
Variable rate (0.07% at 1/1/12) due 2015		**54**	54		
Variable rate (0.16% at 1/1/12) due 2016		**4**	4		
Variable rates (0.03% to 0.18% at 1/1/12) due 2017 to 2049		**1,703**	1,218		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	—		
Total other long-term debt		**3,621**	3,091		
Capitalized lease obligations		**93**	99		
Unamortized debt premium (related to plant acquisition)		**78**	1		
Unamortized debt discount		**(32)**	(28)		
Total long-term debt (annual interest requirement — $865 million)		**20,364**	19,455		
Less amount due within one year		**1,717**	1,301		
Long-term debt excluding amount due within one year		**18,647**	18,154	**50.0%**	51.2%

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CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2011 and 2010
Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	**2011**	2010
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	**81**	81		
$1 par value — 5.20% to 5.83%				
Authorized — 28 million shares				
Outstanding — 12 million shares: $25 stated value	**294**	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $20 million)	**375**	375	**1.0**	1.1
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,328**	4,219		
Authorized — 1.5 billion shares				
Issued — 2011: 866 million shares				
— 2010: 844 million shares				
Treasury — 2011: 0.5 million shares				
— 2010: 0.5 million shares				
Paid-in capital	**4,410**	3,702		
Treasury, at cost	**(17)**	(15)		
Retained earnings	**8,968**	8,366		
Accumulated other comprehensive income (loss)	**(111)**	(70)		
Total common stockholders' equity	**17,578**	16,202	**47.1**	45.7
Preferred and Preference Stock of Subsidiaries:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	**45**	45		
Preference stock				
Authorized — 65 million shares				
Outstanding—$1 par value — 5.63% to 6.50%	**343**	343		
— 14 million shares (non-cumulative)				
— $100 par or stated value — 6.00% to 6.50%	**319**	319		
— 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement — $45 million)	**707**	707	**1.9**	2.0
Total stockholders' equity	**18,285**	16,909		
Total Capitalization	**$37,307**	$35,438	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2011, 2010, and 2009
Southern Company and Subsidiary Companies 2011 Annual Report

	Number of Common Shares		Common Stock						
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Total
	(in thousands)		*(in millions)*						
Balance at December 31, 2008	777,616	(424)	$3,888	$1,893	$(12)	$ 7,612	$ (105)	$707	$13,983
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,643	—	—	1,643
Other comprehensive income (loss)	—	—	—	—	—	—	17	—	17
Stock issued	42,536	—	213	1,074	—	—	—	—	1,287
Stock-based compensation	—	—	—	26	—	—	—	—	26
Cash dividends	—	—	—	—	—	(1,369)	—	—	(1,369)
Other	—	(81)	—	2	(3)	(1)	—	—	(2)
Balance at December 31, 2009	820,152	(505)	4,101	2,995	(15)	7,885	(88)	707	15,585
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,975	—	—	1,975
Other comprehensive income (loss)	—	—	—	—	—	—	18	—	18
Stock issued	23,662	—	118	654	—	—	—	—	772
Stock-based compensation	—	—	—	52	—	—	—	—	52
Cash dividends	—	—	—	—	—	(1,496)	—	—	(1,496)
Other	—	31	—	1	—	2	—	—	3
Balance at December 31, 2010	**843,814**	**(474)**	**4,219**	**3,702**	**(15)**	**8,366**	**(70)**	**707**	**16,909**
Net income after dividends on preferred and preference stock of subsidiaries	**—**	**—**	**—**	**—**	**—**	**2,203**	**—**	**—**	**2,203**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(41)**	**—**	**(41)**
Stock issued	**21,850**	**—**	**109**	**616**	**—**	**—**	**—**	**—**	**725**
Stock-based compensation	**—**	**—**	**—**	**89**	**—**	**—**	**—**	**—**	**89**
Cash dividends	**—**	**—**	**—**	**—**	**—**	**(1,601)**	**—**	**—**	**(1,601)**
Other	**—**	**(65)**	**—**	**3**	**(2)**	**—**	**—**	**—**	**1**
Balance at December 31, 2011	**865,664**	**(539)**	**$4,328**	**$4,410**	**$(17)**	**$ 8,968**	**$ (111)**	**$707**	**$18,285**

The accompanying notes are an integral part of these financial statements.

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NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2011 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (the Company) is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow generally accepted accounting principles (GAAP) in the U.S. and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates.

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NOTES (continued)
Southern Company and Subsidiary Companies 2011 Annual Report

Regulatory Assets and Liabilities

The traditional operating companies are subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2011	2010	Note
	(in millions)		
Deferred income tax charges	**$ 1,293**	$ 1,204	(a)
Deferred income tax charges — Medicare subsidy	**77**	82	(j)
Asset retirement obligations-asset	**117**	79	(a,h)
Asset retirement obligations-liability	**(42)**	(82)	(a,h)
Other cost of removal obligations	**(1,196)**	(1,188)	(a)
Deferred income tax credits	**(225)**	(237)	(a)
State income tax credits	**(62)**	—	(k)
Loss on reacquired debt	**285**	274	(b)
Vacation pay	**160**	151	(c,h)
Under recovered regulatory clause revenues	**50**	27	(d)
Over recovered regulatory clause revenues	**(28)**	(40)	(d)
Building leases	**43**	45	(f)
Generating plant outage costs	**38**	31	(l)
Under recovered storm damage costs	**43**	8	(d)
Property damage reserves	**(206)**	(216)	(g)
Fuel hedging-asset	**249**	211	(d)
Fuel hedging-liability	**(13)**	(7)	(d)
Other assets	**290**	171	(d)
Environmental remediation-asset	**71**	67	(g,h)
Environmental remediation-liability	**(8)**	(10)	(g)
Other liabilities	**(30)**	(13)	(i)
Retiree benefit plans	**2,959**	2,041	(e,h)
Total assets (liabilities), net	**$ 3,865**	$ 2,598	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2011, other cost of removal obligations included $62 million that is being amortized over the remaining two-year period in accordance with an Alternate Rate Plan for Georgia Power for the years 2011 through 2013. See Note 3 under "Retail Regulatory Matters — Georgia Power — Rate Plans" for additional information.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods not exceeding five years.

(e) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.

(f) Recovered over the remaining lives of the buildings through 2026.

(g) Recovered as storm restoration and potential reliability-related expenses or environmental remediation expenses are incurred as approved by the appropriate state PSCs.

(h) Not earning a return as offset in rate base by a corresponding asset or liability.

(i) Recorded and recovered or amortized as approved by the appropriate state PSC over periods up to the life of the plant or the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(j) Recovered and amortized as approved by the appropriate state PSCs over periods not exceeding 14 years. See Note 5 under "Current and

Deferred Income Taxes" for additional information.

(k) Additional tax benefits resulting from the Georgia state income tax credit settlement that will be amortized over a 21-month period beginning April 2012 in accordance with a Georgia PSC order. See Note 3 under "Income Tax Matters – Georgia State Income Tax Credits" for additional information.

(l) Recovered over the respective operating cycles, which range from 18 months to 10 years. See "Property, Plant, and Equipment" herein for additional information.

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In the event that a portion of a traditional operating company's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional operating company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters — Alabama Power," "Retail Regulatory Matters — Georgia Power," and "Integrated Coal Gasification Combined Cycle" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Southern Company's electric utility subsidiaries have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with regulatory requirements, deferred investment tax credits (ITCs) for the traditional operating companies are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $19 million in 2011, $23 million in 2010, and $24 million in 2009. At December 31, 2011, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years.

Under the American Recovery and Reinvestment Act of 2009, certain projects at certain Southern Company subsidiaries are eligible for ITCs or cash grants. These subsidiaries have elected to receive ITCs. The credits are recorded as a deferred credit, and are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $0.9 million in 2011. No credits were amortized in 2010 or 2009. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The subsidiaries have elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period. These basis differences will reverse and be recorded to income tax expense over the useful life of the asset once placed in service.

In accordance with accounting standards related to the uncertainty in income taxes, Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

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Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Southern Company system's property, plant, and equipment in service consisted of the following at December 31:

	2011	2010
	(in millions)	
Generation	**$ 31,751**	$ 30,121
Transmission	**8,240**	7,835
Distribution	**15,458**	14,870
General	**3,413**	3,116
Plant acquisition adjustment	**124**	43
Utility plant in service	**58,986**	55,985
Information technology equipment and software	**220**	216
Communications equipment	**428**	423
Other	**110**	107
Other plant in service	**758**	746
Total plant in service	**$ 59,744**	$ 56,731

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

The amount of non-cash property additions recognized for the years ended December 31, 2011, 2010, and 2009 was $929 million, $427 million, and $370 million, respectively. These amounts are comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year.

Included in the non-cash property additions for the year ended December 31, 2011 was $346 million for the fair value of the debt assumed for Mississippi Power's purchase of the combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4). In 2001, Mississippi Power began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. On July 20, 2011, Mississippi Power provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4. On October 20, 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. The fair value of the debt was determined using a discounted cash flow model based on Mississippi Power's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 are reflected in Southern Company's financial statements at approximately $431 million.

Southern Power has been engaged in acquiring assets. Southern Power has accounted for acquisitions under the acquisition method in accordance with GAAP. The purchase price of each acquisition is allocated to the fair value of the identifiable assets and liabilities, including property, plant, and equipment.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2011, 3.3% in 2010, and 3.2% in 2009. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $20.7 billion and $19.7 billion at December 31, 2011 and 2010, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing Georgia Power to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), Georgia Power is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. See Note 3 under “Retail Regulatory Matters — Georgia Power — Rate Plans” for additional information.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years. Accumulated depreciation for other plant in service totaled $456 million and $441 million at December 31, 2011 and 2010, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset’s future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset’s useful life. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 3 under “Retail Regulatory Matters — Georgia Power — Rate Plans” for additional information related to Georgia Power’s cost of removal regulatory liability.

The liability for asset retirement obligations primarily relates to the Southern Company system’s nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Southern Company system has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the applicable company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See “Nuclear Decommissioning” herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2011	2010
	(in millions)	
Balance at beginning of year	**$ 1,266**	$ 1,206
Liabilities incurred	**1**	—
Liabilities settled	**(13)**	(16)
Accretion	**82**	78
Cash flow revisions	**8**	(2)
Balance at end of year	**$ 1,344**	$ 1,266

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. In addition, the NRC prohibits investments in securities of power reactor licensees. While Southern Company is allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Southern Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to investment brokers for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2011 and 2010, approximately $39 million and $141 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $42 million and $144 million at December 31, 2011 and 2010, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2011, investment securities in the Funds totaled $1.2 billion consisting of equity securities of $626 million, debt securities of $543 million, and $36 million of other securities. At December 31, 2010, investment securities in the Funds totaled $1.4 billion consisting of equity securities of $664 million, debt securities of $632 million, and $74 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $2.2 billion, $2.0 billion, and $1.2 billion in 2011, 2010, and 2009, respectively, all of which were reinvested. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $29 million, of which $41 million related to realized gains and $60 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $139 million, of which $6 million related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $215 million, of which $198 million related to securities held in the Funds at December 31, 2009. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

For Alabama Power, amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

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At December 31, 2011, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
		(in millions)	
External trust funds	$ 540	$ 399	$ 235
Internal reserves	23	—	—
Total	$ 563	$ 399	$ 235

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2008 for Alabama Power's Plant Farley and in 2009 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2065	2063	2067
		(in millions)	
Site study costs:			
Radiated structures	$ 1,060	$ 583	$ 500
Non-radiated structures	72	46	71
Total	$ 1,132	$ 629	$ 571

The decommissioning periods and site study costs for Plant Vogtle reflect the extended operating license approved by the NRC in June 2009. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2009. Current NRC estimates are $584 million and $426 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Amounts expensed were $3 million annually for Plant Vogtle Units 1 and 2 for 2009 and 2010. Effective for the years 2011 through 2013, the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. Georgia Power projects the Funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

As a result of license extensions, amounts previously contributed to the Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

Allowance for Funds Used During Construction and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies record allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 9.1%, 12.5%, and 15.3% of net income for 2011, 2010, and 2009, respectively.

Cash payments for interest totaled $832 million, $789 million, and $788 million in 2011, 2010, and 2009, respectively, net of amounts capitalized of $78 million, $86 million, and $84 million, respectively.

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Impairment of Long-Lived Assets and Intangibles

Southern Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $29 million in 2011 and $32 million in 2010. Alabama Power, Gulf Power, and Mississippi Power also have discretionary authority from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2011 and 2010, such additional accruals totaled $31 million and $48 million, respectively, all at Alabama Power. See Note 3 under "Retail Regulatory Matters — Alabama Power — Natural Disaster Reserve" for additional information regarding Alabama Power's natural disaster reserve.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the asset. Southern Company will continue to monitor the performance of the underlying assets and to evaluate the ability of the lessee to continue to make the required lease payments. While there are strategic options that Southern Company may pursue to recover its investment in the leveraged lease, the potential impairment loss that would be incurred if there is an abandonment of the project is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Southern Company's net investment in domestic leveraged leases consists of the following at December 31:

	2011	2010
	(in millions)	
Net rentals receivable	**$ 482**	$ 475
Unearned income	**(205)**	(207)
Investment in leveraged leases	**277**	268
Deferred taxes from leveraged leases	**(238)**	(223)
Net investment in leveraged leases	**$ 39**	$ 45

A summary of the components of income from domestic leveraged leases follows:

	2011	2010	2009
		(in millions)	
Pretax leveraged lease income	**$ 10**	$ 4	$ 12
Income tax expense	**(4)**	(3)	(5)
Net leveraged lease income	**$ 6**	$ 1	$ 7

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Southern Company's net investment in international leveraged leases consists of the following at December 31:

	2011	2010
	(in millions)	
Net rentals receivable	$ 734	$ 733
Unearned income	(362)	(377)
Investment in leveraged leases	372	356
Deferred taxes from leveraged leases	(39)	(40)
Net investment in leveraged leases	$ 333	$ 316

A summary of the components of income from international leveraged leases follows:

	2011	2010	2009
		(in millions)	
Pretax leveraged lease income (loss)	$ 15	$ 14	$ 19
Income tax benefit (expense)	(5)	(5)	(7)
Net leveraged lease income (loss)	$ 10	$ 9	$ 12

The Company terminated two international leveraged lease investments during 2009. The proceeds were used to extinguish all debt related to leveraged lease investments, a portion of which had make-whole redemption provisions. This resulted in a $17 million loss which partially offset a $26 million gain on the terminations.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

Southern Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of Southern Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel hedging programs. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

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The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2011, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was not material.

Southern Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income after dividends on preferred and preference stock of subsidiaries, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
			(in millions)	
Balance at December 31, 2010	$(35)	$ 7	$(42)	$ (70)
Current period change	(9)	(4)	(28)	(41)
Balance at December 31, 2011	**$(44)**	**$ 3**	**$(70)**	**$(111)**

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this accounting guidance did not result in the traditional operating companies or Southern Power consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

Certain of the traditional operating companies have established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, Southern Company and the applicable traditional operating companies are not considered the primary beneficiaries of the trusts. Therefore, the investments in these trusts are reflected as other investments, and the related loans from the trusts are reflected in long-term debt in the balance sheets.

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2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2012, other postretirement trust contributions are expected to total approximately $31 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.52%	5.93%
Other postretirement benefit plans	**4.88**	5.40	5.83
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.39**	7.40	7.51

* Net of estimated investment management expenses of 30 basis points.

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate Is Reached**
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2011 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$125	$(106)
Service and interest costs	7	(6)

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Pension Plans

The total accumulated benefit obligation for the pension plans was $7.4 billion at December 31, 2011 and $6.7 billion at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 7,223**	$ 6,758
Service cost	**184**	172
Interest cost	**389**	391
Benefits paid	**(324)**	(296)
Actuarial loss (gain)	**607**	198
Balance at end of year	**8,079**	7,223
Change in plan assets		
Fair value of plan assets at beginning of year	**6,834**	5,627
Actual return (loss) on plan assets	**256**	859
Employer contributions	**34**	644
Benefits paid	**(324)**	(296)
Fair value of plan assets at end of year	**6,800**	6,834
Accrued liability	**$ (1,279)**	$ (389)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $7.5 billion and $0.5 billion, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in millions)	
Prepaid pension costs	**$ —**	$ 88
Other regulatory assets, deferred	**2,614**	1,749
Other current liabilities	**(34)**	(28)
Employee benefit obligations	**(1,245)**	(449)
Accumulated OCI	**109**	68

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2011 and 2010 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2012.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2011:		
Accumulated OCI	**$ 7**	**$ 102**
Regulatory assets	**128**	**2,486**
Total	**$135**	**$2,588**
Balance at December 31, 2010:		
Accumulated OCI	$ 8	$ 60
Regulatory assets	159	1,590
Total	$167	$1,650
Estimated amortization in net periodic pension cost in 2012:		
Accumulated OCI	$ 1	$ 4
Regulatory assets	29	91
Total	$ 30	$ 95

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The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2009	$ 74	$1,894
Net (gain) loss	(4)	(106)
Change in prior service costs	—	2
Reclassification adjustments:		
Amortization of prior service costs	(1)	(32)
Amortization of net gain (loss)	(1)	(9)
Total reclassification adjustments	(2)	(41)
Total change	(6)	(145)
Balance at December 31, 2010	$ 68	$1,749
Net (gain) loss	**43**	**915**
Change in prior service costs	**—**	**1**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(31)**
Amortization of net gain (loss)	**(1)**	**(20)**
Total reclassification adjustments	**(2)**	**(51)**
Total change	**41**	**865**
Balance at December 31, 2011	**$109**	**$2,614**

Components of net periodic pension cost were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 184**	$ 172	$ 146
Interest cost	**389**	391	387
Expected return on plan assets	**(607)**	(552)	(541)
Recognized net loss	**21**	10	7
Net amortization	**32**	33	35
Net periodic pension cost	**$ 19**	$ 54	$ 34

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets. Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2012	$ 361
2013	380
2014	398
2015	418
2016	438
2017 to 2021	2,488

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Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,752**	$ 1,759
Service cost	**21**	25
Interest cost	**92**	100
Benefits paid	**(103)**	(95)
Actuarial loss (gain)	**29**	(41)
Plan amendments	**(12)**	(2)
Retiree drug subsidy	**8**	6
Balance at end of year	**1,787**	1,752
Change in plan assets		
Fair value of plan assets at beginning of year	**802**	743
Actual return (loss) on plan assets	**4**	82
Employer contributions	**54**	66
Benefits paid	**(95)**	(89)
Fair value of plan assets at end of year	**765**	802
Accrued liability	**$ (1,022)**	$ (950)

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in millions)	
Other regulatory assets, deferred	**$ 345**	$ 292
Other current liabilities	**(4)**	(1)
Employee benefit obligations	**(1,018)**	(949)
Accumulated OCI	**6**	3

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2011:			
Accumulated OCI	**$—**	**$ 6**	**$—**
Regulatory assets	**17**	**314**	**14**
Total	**$17**	**$320**	**$14**
Balance at December 31, 2010:			
Accumulated OCI	$—	$ 3	$—
Regulatory assets	34	233	25
Total	$34	$236	$25
Estimated amortization as net periodic postretirement benefit cost in 2012:			
Accumulated OCI	$—	$ —	$—
Regulatory assets	4	6	10
Total	$ 4	$ 6	$10

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The components of OCI, along with the changes in the balance of regulatory assets, related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2009	$ 5	$ 374
Net (gain) loss	(2)	(60)
Change in prior service costs/transition obligation	—	(2)
Reclassification adjustments:		
Amortization of transition obligation	—	(10)
Amortization of prior service costs	—	(5)
Amortization of net gain (loss)	—	(5)
Total reclassification adjustments	—	(20)
Total change	(2)	(82)
Balance at December 31, 2010	$ 3	$ 292
Net (gain) loss	**3**	**84**
Change in prior service costs/transition obligation	**—**	**(12)**
Reclassification adjustments:		
Amortization of transition obligation	**—**	**(10)**
Amortization of prior service costs	**—**	**(5)**
Amortization of net gain (loss)	**—**	**(4)**
Total reclassification adjustments	**—**	**(19)**
Total change	**3**	**53**
Balance at December 31, 2011	**$ 6**	**$ 345**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 21**	$ 25	$ 26
Interest cost	**92**	100	113
Expected return on plan assets	**(64)**	(63)	(61)
Net amortization	**20**	20	25
Net postretirement cost	**$ 69**	$ 82	$103

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2012	$110	$(10)	$100
2013	116	(12)	104
2014	122	(13)	109
2015	128	(15)	113
2016	133	(16)	117
2017 to 2021	691	(90)	601

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Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**—**	—
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**39%**	40%
International equity	17	**18**	21
Domestic fixed income	30	**31**	29
Global fixed income	3	**4**	3
Special situations	1	**—**	—
Real estate investments	5	**5**	4
Private equity	3	**3**	3
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

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Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

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The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

As of December 31, 2011:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$1,155	$ 533	$ —	$1,688
International equity*	1,187	340	—	1,527
Fixed income:				
U.S. Treasury, government, and agency bonds	—	433	—	433
Mortgage- and asset-backed securities	—	135	—	135
Corporate bonds	—	832	3	835
Pooled funds	—	380	—	380
Cash equivalents and other	1	139	—	140
Real estate investments	220	—	782	1,002
Private equity	—	—	582	582
Total	$2,563	$2,792	$1,367	$6,722

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$1,266	$ 511	$ 1	$1,778
International equity*	1,277	443	—	1,720
Fixed income:				
U.S. Treasury, government, and agency bonds	—	304	—	304
Mortgage- and asset-backed securities	—	247	—	247
Corporate bonds	—	594	2	596
Pooled funds	—	201	—	201
Cash equivalents and other	2	478	—	480
Real estate investments	184	—	674	858
Private equity	—	—	638	638
Total	$2,729	$2,778	$1,315	$6,822
Liabilities:				
Derivatives	(1)	—	—	(1)
Total	$2,728	$2,778	$1,315	$6,821

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$674**	**$638**	$547	$555
Actual return on investments:				
Related to investments held at year end	**72**	**(12)**	59	67
Related to investments sold during the year	**20**	**47**	18	18
Total return on investments	**92**	**35**	77	85
Purchases, sales, and settlements	**16**	**(91)**	50	(2)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$782**	**$582**	$674	$638

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
	(in millions)			
Assets:				
Domestic equity*	$156	$ 38	$—	$194
International equity*	45	39	—	84
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	5	—	5
Corporate bonds	—	32	—	32
Pooled funds	—	48	—	48
Cash equivalents and other	—	46	—	46
Trust-owned life insurance	—	291	—	291
Real estate investments	9	—	30	39
Private equity	—	—	23	23
Total	$210	$523	$53	$786

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$176	$ 45	$—	$221
International equity*	49	50	—	99
Fixed income:				
U.S. Treasury, government, and agency bonds	—	15	—	15
Mortgage- and asset-backed securities	—	10	—	10
Corporate bonds	—	23	—	23
Pooled funds	—	34	—	34
Cash equivalents and other	—	41	—	41
Trust-owned life insurance	—	291	—	291
Real estate investments	7	—	26	33
Private equity	—	—	23	23
Total	$232	$509	$49	$790

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$26**	**$23**	$24	$24
Actual return on investments:				
Related to investments held at year end	**3**	**—**	2	1
Related to investments sold during the year	**1**	**2**	—	—
Total return on investments	**4**	**2**	2	1
Purchases, sales, and settlements	**—**	**(2)**	—	(2)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$30**	**$23**	$26	$23

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee’s base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $78 million, $76 million, and $78 million, respectively.

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3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2011 was $17 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated; however, they are not expected to have a material impact on Southern Company's financial statements.

In 2008, the EPA advised Georgia Power that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA.

On September 29, 2011, the EPA issued a unilateral administrative order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the Ward Transformer Superfund site. Georgia Power does not believe it is a liable party under CERCLA based on its alleged connection to the site. As a result, on November 7, 2011, Georgia Power filed a response with the EPA indicating that Georgia Power is not willing to undertake the work set forth in the UAO because Georgia Power has sufficient cause to believe it is not a liable party. On November 22, 2011, the EPA sent Georgia Power a letter stating that the EPA does not consider Georgia Power to be in compliance with the UAO. The EPA also stated that it is considering enforcement options against Georgia Power and other UAO recipients who are not complying with the UAO.

The EPA may seek to enforce the UAO in court pursuant to its enforcement authority under CERCLA and may seek recovery of its costs in undertaking the UAO work. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at the Ward Transformer Superfund site, in 2009, Georgia Power, along with many other parties, was sued by several existing PRPs for cost recovery for a removal action that is currently taking place. Georgia Power and numerous other defendants moved for a dismissal of these lawsuits. The court denied the dismissal of the lawsuits in March 2010 but granted Georgia Power's motion regarding the dismissal of the claim pertaining to the plaintiffs' joint and several liability.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory treatment, it is not expected to have a material impact on Southern Company's financial statements.

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Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $62 million as of December 31, 2011. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements .

Nuclear Fuel Disposal Costs

Alabama Power and Georgia Power have contracts with the U.S., acting through the U.S. Department of Energy (DOE), that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract.

In 2007, the U.S. Court of Federal Claims awarded Georgia Power approximately $30 million, based on its ownership interests, and awarded Alabama Power approximately $17 million, representing substantially all of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004.

In 2008, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to Alabama Power, but remanded the Georgia Power portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit. Georgia Power filed a motion for summary judgment related to a portion of the costs, which remains pending. On July 12, 2011, the court entered final judgment in favor of Alabama Power and awarded Alabama Power approximately $17 million. In April 2012, the award will be credited to cost of service for the benefit of customers.

In 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim) due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2011 for the second claim.

The final outcome of these matters cannot be determined at this time, but no material impact on Southern Company's net income is expected as a significant portion of any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

Income Tax Matters

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. In 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, Georgia Power and the Georgia Department of Revenue agreed to a settlement resolving the claims. As a result, Georgia Power recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, Georgia Power recorded a reduction of approximately $23 million in related interest expense. See "Retail Regulatory Matters – Georgia Power – Other Construction" herein for additional information on the regulatory liability.

Retail Regulatory Matters

Alabama Power

Retail Rate Adjustments

On July 12, 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the natural disaster reserve (NDR) in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information.

Rate RSE

Alabama Power operates under rate stabilization and equalization (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, Alabama Power agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated power purchase agreements (PPAs) under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, Alabama Power had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Alabama Power's rate certificated new plant environmental (Rate CNP Environmental) also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that Alabama Power leave in effect for 2012 the factors associated with Alabama Power's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, Alabama Power had an under recovered environmental clause balance of $11 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

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Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. On September 7, 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Fuel Cost Recovery

Alabama Power has established fuel cost recovery rates under Alabama Power's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. On December 6, 2011, the Alabama PSC issued a consent order that Alabama Power leave in effect the fuel cost recovery rates which began in April 2011 for 2012. Therefore, the Rate ECR factor as of January 1, 2012 remained at 2.681 cents per KWH. Effective with billings beginning in January 2013, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2011 and 2010, Alabama Power had an under recovered fuel balance of approximately $31 million and $4 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Alabama Power has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows Alabama Power to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred on April 27, 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

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In accordance with the order that was issued by the Alabama PSC on July 12, 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balance in the NDR for the year ended December 31, 2011 was approximately $110 million. For the year ended December 31, 2010, Alabama Power accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

In August 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In December 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

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Under the 2010 ARP, the following additional base rate adjustments have been or will be made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Other Construction" below for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, Georgia Power's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2010 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

2011 Integrated Resource Plan Update

On August 4, 2011, Georgia Power filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included Georgia Power's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. Georgia Power also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, Georgia Power is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 megawatts (MWs) of capacity. Georgia Power is currently updating its economic analysis of these units based on the final Mercury and Air Toxics Standards (MATS) rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, Georgia Power cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes Georgia Power's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process. If approved, these PPAs are expected to result in additional contractual obligations of approximately $84 million in 2015, $102 million in 2016, and $1.4 billion thereafter.

In addition, Georgia Power filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, Georgia Power entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated Integrated Resource Plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decision, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Southern Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved an increase in Georgia Power's total annual billings of approximately $373 million effective April 2010, as well as a decrease of approximately $43 million effective June 1, 2011. In addition, the Georgia PSC has authorized an interim fuel rider, which allows Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. Georgia Power currently expects to file its next case on March 30, 2012, with rates to be effective July 1, 2012.

At December 31, 2011, Georgia Power's under recovered fuel balance totaled approximately $137 million, all of which is included in current assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Nuclear Construction

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of Georgia Power, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4). See Note 4 for additional information on the Owners. In 2008, Southern Nuclear filed applications with the NRC for the combined construction and operating licenses (COLs) for the new units. The NRC certified the Westinghouse Electric Company LLC's (Westinghouse) Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively.

On February 16, 2012, a group of four plaintiffs who had intervened in the NRC's COL proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the DCD. The Company intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows Georgia Power to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered Georgia Power to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved Georgia Power's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and annual adjustments are filed with the Georgia PSC on November 1 to become effective on January 1 of the following year. Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2011, approximately $73 million of these 2009 and 2010 costs remained in construction work in progress. At December 31, 2011, Georgia Power's portion of construction work in progress for Plant Vogtle Units 3 and 4 was $1.9 billion.

On February 10, 2012, the Georgia PSC voted to approve Georgia Power's fifth semi-annual construction monitoring report including total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. Georgia Power will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2008, Georgia Power, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 MWs each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COLs or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in accordance with the Vogtle 3 and 4 Agreement in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and Georgia Power (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including potential costs associated with design changes the Consortium made to the DCD during the NRC review process and potential costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Consortium has not specified the amount of these costs, but such costs could be substantial, and Georgia Power expects the Consortium to seek recovery of these costs. Georgia Power is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the Vogtle 3 and 4 Agreement. Georgia Power has not agreed that the Owners have responsibility for any of these costs and, with regard to most of these costs, denies any liability and Georgia Power intends to vigorously defend itself in these matters. Georgia Power expects negotiations with the Consortium to continue over the next several months. If these costs are imposed upon the Owners, Georgia Power would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4 if necessary. Additional claims by the Consortium and Georgia Power (on behalf of the Owners) may arise throughout the construction of Plant Vogtle Units 3 and 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC's issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

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Other Construction

Georgia Power is currently constructing Plant McDonough Units 5 and 6 which are expected to be placed into service in May and November 2012, respectively. Georgia Power completed construction of Plant McDonough Unit 4 and placed it into service on December 28, 2011. On January 24, 2012, the Georgia PSC approved a stipulation agreement between Georgia Power and the Georgia PSC Public Interest Advocacy Staff to increase the certified amount for the project by 3.9% and to amortize $62 million of a regulatory liability for state income tax credits over a 21-month period beginning April 2012. See "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information on this regulatory liability and "Rate Plans" above for additional information on base rate increases in 2012 and 2013 associated with the new units.

The Georgia PSC has also approved Georgia Power's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2011. Georgia Power will continue to file quarterly construction monitoring reports throughout the construction period.

Integrated Coal Gasification Combined Cycle

Mississippi Power is constructing a new electric generating facility located in Kemper County, Mississippi that will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs (Kemper IGCC). In May 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming Mississippi Power's application for a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN.

The estimated cost of the plant is $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2). The Mississippi PSC's order (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's proposal, and (3) approved financing cost recovery on construction work in progress (CWIP) balances, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by Mississippi Power in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $245 million. In May 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operations operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits.

In 2009, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $133 million of Internal Revenue Code Section 48A tax credits (Phase I) to Mississippi Power. On April 19, 2011, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to Mississippi Power. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits.

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Through December 31, 2011, Mississippi Power received or accrued tax benefits totaling $100 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be able to utilize $77 million of these tax credits until after 2012. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then.

In 2008, Mississippi Power requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled integrated coal gasification combined cycle project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida, and, later in 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Through December 31, 2011, Mississippi Power received grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for its initial operation.

On March 10, 2011, the Sierra Club filed a lawsuit in the U.S. District Court for the District of Columbia against the DOE regarding the National Environmental Policy Act review process for the Kemper IGCC asking for a preliminary and permanent injunction on the issuance of CCPI2 funds and loan guarantees and a stay to any related construction activities based upon alleged deficiencies in the DOE's environmental impact statement. Mississippi Power intervened as a party in this lawsuit on May 18, 2011. On November 18, 2011, the U.S. District Court for the District of Columbia denied the Sierra Club's motion for preliminary injunction in the case and dismissed with prejudice the portion of the Sierra Club's claim relating to loan guarantees. On February 2, 2012, the Sierra Club filed for a voluntary dismissal with prejudice of all claims against the DOE pending in the U.S. District Court for the District of Columbia.

In March 2010, the MDEQ issued the Prevention of Significant Deterioration (PSD) air permit modification for the Kemper IGCC, which modifies the original PSD air permit issued in 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board unanimously affirmed the PSD air permit. On June 30, 2011, the Sierra Club appealed the final PSD air permit issued by the MDEQ to the Chancery Court of Kemper County, Mississippi. Mississippi Power has intervened as a party in this appeal.

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club's direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the Mississippi PSC's order authorizing the construction of the Kemper IGCC. On March 1, 2011, the Sierra Club appealed the Chancery Court's decision to the Mississippi Supreme Court.

In July 2010, Mississippi Power and South Mississippi Electric Power Association (SMEPA) entered into an Asset Purchase Agreement whereby SMEPA agreed to purchase a 17.5% undivided ownership interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In December 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

On March 4, 2011, Mississippi Power and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC. On May 19, 2011, Mississippi Power and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tenrgys, LLC, entered into a contract pursuant to which Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC.

On April 27, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-A (CNP-A), a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. As part of the review of the mechanism, the Mississippi PSC will consider costs to be included as well as the allowed rate of return. CNP-A rate filings are made annually. The first filing was made on November 15, 2011 and requested an 11.66% increase in rates, or approximately $98 million annually, to recover these financing costs. If approved by the Mississippi PSC, CNP-A will remain in place thereafter until the end of the calendar year that the Kemper IGCC is placed into commercial service, which is projected to be 2014.

On August 9, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-B (CNP-B) to govern rates effective from the first calendar year after the Kemper IGCC is placed into commercial service through the first seven full calendar years of its operation. Under the proposed CNP-B, Mississippi Power's allowed cost of capital would be adjusted based on certain operational performance indicators.

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On June 7, 2011, consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities for the Kemper IGCC. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

On September 9, 2011, Mississippi Power filed a request for confirmation of the Kemper IGCC's CPCN with the Mississippi PSC authorizing the acquisition, construction, and operation of approximately 61 miles of CO_2 pipeline infrastructure at an estimated capital cost of $141 million. On January 11, 2012, the Mississippi PSC affirmed the confirmation of the Kemper IGCC's CPCN for the acquisition, construction, and operation of the CO_2 pipeline.

As of December 31, 2011, Mississippi Power had spent a total of $943 million on the Kemper IGCC, including regulatory filing costs. Of this total, $918 million was included in CWIP (which is net of $245 million of CCPI2 grant funds), $21 million was recorded in other regulatory assets, $3 million was recorded in other deferred charges and assets, and $1 million was previously expensed.

The ultimate outcome of these matters cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with Power South Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Florida Power Corporation for a combustion turbine unit at Intercession City, Florida. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2011, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership	Amount of Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear) Units 1 and 2	45.7%	$3,296	$1,962
Plant Hatch (nuclear)	50.1	978	545
Plant Miller (coal) Units 1 and 2	91.8	1,389	510
Plant Scherer (coal) Units 1 and 2	8.4	157	76
Plant Wansley (coal)	53.5	709	225
Rocky Mountain (pumped storage)	25.4	175	113
Intercession City (combustion turbine)	33.3	12	4
Plant Stanton (combined cycle) Unit A	65.0	154	27

At December 31, 2011, the portion of total construction work in progress related to Plants Miller, Scherer, and Wansley was $7 million, $63 million, and $36 million, respectively. Construction at Plants Miller, Wansley, and Scherer relates primarily to environmental projects.

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

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5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, Mississippi, and Texas. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in millions)	
Federal —			
Current	**$ 57**	$ 42	$771
Deferred	**1,035**	898	40
	$1,092	940	811
State —			
Current	**8**	(54)	100
Deferred	**119**	140	(15)
	127	86	85
Total	**$1,219**	$1,026	$896

Net cash payments/(refunds) for income taxes in 2011, 2010, and 2009 were $(401) million, $276 million, and $975 million, respectively.

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 7,882**	$ 6,833
Property basis differences	**1,256**	1,150
Leveraged lease basis differences	**277**	263
Employee benefit obligations	**499**	485
Under recovered fuel clause	**82**	179
Premium on reacquired debt	**111**	109
Regulatory assets associated with employee benefit obligations	**1,198**	814
Regulatory assets associated with asset retirement obligations	**546**	509
Other	**276**	215
Total	**12,127**	10,557
Deferred tax assets —		
Federal effect of state deferred taxes	**393**	386
State effect of federal deferred taxes	**1**	50
Employee benefit obligations	**1,594**	1,179
Over recovered fuel clause	**33**	40
Other property basis differences	**134**	119
Deferred costs	**55**	100
Cost of removal	**40**	52
Tax credit carryforward	**129**	192
Unbilled revenue	**110**	126
Other comprehensive losses	**81**	69
Asset retirement obligations	**546**	509
Other	**357**	331
Total	**3,473**	3,153
Total deferred tax liabilities, net	**8,654**	7,404
Portion included in prepaid expenses (accrued income taxes), net	**125**	117
Deferred state tax assets	**86**	91
Valuation allowance	**(56)**	(58)

Accumulated deferred income taxes	**$ 8,809**	$ 7,554

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At December 31, 2011, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $879 million, which could result in net state income tax benefits of $51 million, if utilized. However, the subsidiaries have established a valuation allowance for the potential $51 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2012 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2011, the tax-related regulatory assets to be recovered from customers were $1.4 billion. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, $82 million was deferred as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The traditional operating companies will recover and amortize the regulatory asset as approved by the state PSCs over periods not exceeding 15 years.

At December 31, 2011, the tax-related regulatory liabilities to be credited to customers were $224 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $19 million in 2011, $23 million in 2010, and $24 million in 2009. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had not been utilized. The remaining investment tax credits will be carried forward and utilized in future years.

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.4**	1.8	2.1
Employee stock plans dividend deduction	**(1.1)**	(1.2)	(1.4)
Non-deductible book depreciation	**0.7**	0.8	0.9
Difference in prior years' deferred and current tax rate	**(0.1)**	(0.1)	(0.1)
AFUDC-Equity	**(1.5)**	(2.2)	(2.7)
Production activities deduction	**—**	—	(0.7)
ITC basis difference	**(0.2)**	(0.4)	—
Leveraged lease termination	**—**	—	(0.9)
MC Asset Recovery	**—**	—	2.7
Donations	**—**	—	(0.4)
Other	**(0.2)**	(0.2)	(0.1)
Effective income tax rate	**35.0%**	33.5%	34.4%

Southern Company's effective tax rate is lower than or equal to the statutory rate primarily due to the employee stock plans' dividend deduction and AFUDC equity, which is not taxable.

Southern Company's 2011 effective tax rate increased from 2010 primarily due to less AFUDC equity capitalized and no Georgia state income tax credits for activity through Georgia ports available to Southern Company in 2011. Additionally, the tax benefit of the basis difference associated with investment tax credits realized during construction decreased in 2011 as compared to 2010.

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Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $176 million, resulting in a balance of $120 million as of December 31, 2011.

Changes during the year in unrecognized tax benefits were as follows:

	2011	2010	2009
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 296**	$199	$146
Tax positions from current periods	**46**	62	53
Tax positions increase from prior periods	**1**	62	12
Tax positions decrease from prior periods	**(111)**	(27)	(10)
Reductions due to settlements	**(112)**	—	—
Reductions due to expired statute of limitations	**—**	—	(2)
Balance at end of year	**$ 120**	$296	$199

The tax positions from current periods for 2011 relate primarily to a litigation settlement refund claim in 2009 relating to MC Asset Recovery, LLC, the tax accounting method change for repairs-generation assets, and other miscellaneous tax positions. See “Effective Tax Rate” herein for additional information. The tax positions decrease from prior periods and reductions due to settlements for 2011 relate to the settlement of the Georgia state tax credit litigation on June 10, 2011. See Note 3 under “Income Tax Matters — Georgia State Income Tax Credits” for additional information. In addition, the tax positions decrease from prior periods for 2011 also relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See “Tax Method of Accounting for Repairs” herein for additional information.

The impact on Southern Company’s effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in millions)	
Tax positions impacting the effective tax rate	**$ 69**	$217	$199
Tax positions not impacting the effective tax rate	**51**	79	—
Balance of unrecognized tax benefits	**$120**	$296	$199

The tax positions impacting the effective tax rate for 2011 primarily relate to the production activities deduction tax position and the 2009 litigation settlement refund claim referenced above. See “Effective Tax Rate” herein for additional information. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See “Tax Method of Accounting for Repairs” herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in millions)	
Interest accrued at beginning of year	**$ 29**	$21	$15
Interest reclassified due to settlements	**(24)**	—	—
Interest accrued during the year	**5**	8	6
Balance at end of year	**$ 10**	$29	$21

Southern Company classifies interest on tax uncertainties as interest expense. The interest reclassified due to settlements in 2011 is primarily associated with the Georgia state tax credit litigation settled on June 10, 2011.

Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of Southern Company’s unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

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The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, Southern Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change for repair costs associated with its subsidiaries' generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $297 million for Southern Company on a consolidated basis. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

Certain of the traditional operating companies formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the applicable traditional operating company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2011 and $412 million as of December 31, 2010, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt. Each traditional operating company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trust's payment obligations with respect to these securities. At December 31, 2011 and 2010, trust preferred securities of $200 million and $400 million, respectively, were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2011	2010
	(in millions)	
Pollution control revenue bonds	**$ —**	$ 8
Capitalized leases	**24**	23
Senior notes	**1,200**	600
Other long-term debt	**493**	670
Total	**$1,717**	$1,301

Maturities through 2016 applicable to total long-term debt are as follows: $1.7 billion in 2012; $2.1 billion in 2013; $449 million in 2014; $1.2 billion in 2015; and $1.2 billion in 2016.

Bank Term Loans

Certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). At December 31, 2011 and 2010, certain of the traditional operating companies (Georgia Power and Mississippi Power) had outstanding bank term loans totaling $690 million and $615 million, respectively. During 2011, Georgia Power entered into $250 million aggregate principal amount of long-term bank loans and $200 million aggregate principal amount of short-term bank loans. Also during 2011, Mississippi Power entered into $240 million aggregate principal amount of long-term bank loans. The proceeds of these loans were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

Subsequent to December 31, 2011, Georgia Power entered into a floating rate six-month short-term bank loan in an aggregate principal amount of $100 million bearing interest based on one-month LIBOR.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2011, Georgia Power and Mississippi Power were each in compliance with their respective debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. Georgia Power and Mississippi Power are currently in compliance with all such covenants.

Senior Notes

Southern Company and its subsidiaries issued a total of $2.8 billion of senior notes in 2011. Southern Company issued $500 million, and the traditional operating companies' and Southern Power's combined issuances totaled $2.3 billion. The proceeds of these issuances were used to repay long-term and short-term indebtedness, to fund acquisitions, and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

At December 31, 2011 and 2010, Southern Company and its subsidiaries had a total of $15.9 billion and $15.2 billion, respectively, of senior notes outstanding. At December 31, 2011 and 2010, Southern Company had a total of $1.8 billion and $1.6 billion, respectively, of senior notes outstanding.

Subsequent to December 31, 2011, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

Subsequent to December 31, 2011, Alabama Power issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including Alabama Power's continuous construction program.

Subsequent to December 31, 2011, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The traditional operating companies had $3.4 billion and $3.1 billion of outstanding pollution control revenue bonds at December 31, 2011 and 2010, respectively. The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Subsequent to December 31, 2011, Alabama Power announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

Plant Daniel Revenue Bonds

In October 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 21, 2021, issued for the benefit of the lessor. See Note 1 under "Property, Plant, and Equipment" and "Assets Subject to Lien" herein for additional information.

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Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds. Mississippi Power had $50 million and $100 million of such obligations outstanding at December 31, 2011 and 2010, respectively. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain pollution control revenue bonds with an outstanding principal amount of $194 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

On October 20, 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value (with a fair value on the assumption date of $346 million) of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Property, Plant, and Equipment" for additional information.

Bank Credit Arrangements

At December 31, 2011, committed credit arrangements with banks were as follows:

	Expires [(a)]						Due Within One Year		Executable Term-Loans	
Company	**2012**	**2013**	**2014**	**2016**	**Total**	**Unused**	**Term Out**	**No Term Out**	**One Year**	**Two Years**
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$—	$ —	$1,000	$1,000	$1,000	$ —	$ —	$ —	$—
Alabama Power	121	35	350	800	1,306	1,306	51	71	51	—
Georgia Power	—	—	250	1,500	1,750	1,745	—	—	—	—
Gulf Power	75	—	165	—	240	240	75	—	75	—
Mississippi Power	131	—	165	—	296	296	66	65	25	41
Southern Power	—	—	—	500	500	500	—	—	—	—
Other	25	25	—	—	50	50	25	—	25	—
Total	$352	$60	$930	$3,800	$5,142	$5,137	$217	$136	$176	$41

(a) No credit arrangements expire in 2015.

Most of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average approximately 1/4 of 1% or less for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Most of the credit arrangements with banks have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities. At December 31, 2011, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the applicable borrower defaulted on indebtedness over a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants.

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A portion of the $5.1 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2011 was approximately $1.8 billion.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings, excluding notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$654	0.28%	$697	0.29%	$1,586
Short-term bank debt	200	1.18%	14	1.21%	200
Total	$854	0.49%	$711	0.32%	
December 31, 2010:					
Commercial paper	$1,295	0.32%	$690	0.29%	$1,305

(a) Average and maximum amounts are based upon daily balances during the period.

Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision that would allow the holders to elect a majority of such subsidiary's board. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are required to be shown as "noncontrolling interest," separately presented as a component of "Stockholders' Equity" on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

There were no changes for the years ended December 31, 2011, 2010, and 2009 in redeemable preferred stock of subsidiaries for Southern Company.

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7. COMMITMENTS

Construction Program

The construction programs of the Company's subsidiaries are currently estimated to include a base level investment of $5.3 billion, $4.4 billion, and $4.3 billion for 2012, 2013, and 2014, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $425 million, $405 million, and $621 million for 2012, 2013, and 2014, respectively. In addition to these base level environmental expenditures there are other potential incremental environmental compliance investments that may be necessary to comply with the EPA's final MATS rule and the proposed water and coal combustion byproducts rules. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2011, significant purchase commitments were outstanding in connection with the continuous construction program, which includes new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Integrated Coal Gasification Combined Cycle" for additional information.

Long-Term Service Agreements

The traditional operating companies and Southern Power have entered into long-term service agreements (LTSAs) with General Electric (GE), Alstom Power, Inc., Mitsubishi Power Systems Americas, Inc., and Siemens AG for the purpose of securing maintenance support for the combined cycle and combustion turbine generating facilities owned or under construction by the subsidiaries. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each LTSA.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments under the LTSAs, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments under these LTSAs for facilities owned are currently estimated at $1.9 billion over the remaining life of the LTSAs, which are currently estimated to range up to 34 years. However, the LTSAs contain various cancellation provisions at the option of the respective traditional operating company or Southern Power, as applicable.

Georgia Power has also entered into a LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $4.5 million. The contract contains cancellation provisions at the option of Georgia Power.

Payments made under the LTSAs prior to the performance of any work are recorded as a prepayment in the balance sheets. All work performed is capitalized or charged to expense (net of any joint owner billings), as appropriate based on the nature of the work.

Limestone Commitments

As part of Southern Company's program to reduce sulfur dioxide emissions from its coal plants, the traditional operating companies have entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. Southern Company has a minimum contractual obligation of 5.6 million tons, equating to approximately $246 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $41 million in 2012, $42 million in 2013, $42 million in 2014, $29 million in 2015, and $22 million in 2016.

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Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2011. Also, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity.

Total estimated minimum long-term obligations at December 31, 2011 were as follows:

	Commitments			
	Natural Gas	Coal	Nuclear Fuel	Purchased Power*
	(in millions)			
2012	$1,479	$3,266	$ 353	$ 259
2013	1,553	2,218	197	248
2014	1,196	1,336	206	281
2015	998	592	145	311
2016	937	300	92	301
2017 and thereafter	2,798	737	740	2,700
Total	$8,961	$8,449	$1,733	$4,100

* Certain PPAs reflected in the table are accounted for as operating leases.

Additional commitments for fuel will be required to supply the Southern Company system's future needs. Total charges for nuclear fuel included in fuel expense amounted to $215 million in 2011, $184 million in 2010, and $160 million in 2009.

Coal commitments for Mississippi Power include a minimum annual management fee of $38 million beginning in 2014 from the executed 40-year management contract with Liberty Fuels related to the Kemper IGCC.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $176 million, $188 million, and $186 million for 2011, 2010, and 2009, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Barges & Rail Cars	Other	Total
	(in millions)		
2012	$ 79	$ 42	$121
2013	68	34	102
2014	53	28	81
2015	21	22	43
2016	15	17	32
2017 and thereafter	10	75	85
Total	$246	$218	$464

For the traditional operating companies, a majority of the barge and rail car lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2012, 2013, 2014, 2015, 2016, and 2018 and the maximum obligations under these leases are $1 million, $39 million, $18 million, $5 million, $4 million, and $24 million, respectively. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

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Guarantees

As discussed earlier in this Note under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2011, Southern Company issued 21.9 million shares of common stock for $723 million through the Southern Investment Plan and employee and director stock plans. In 2010, Southern Company raised $629 million from the issuance of 19.6 million new common shares through the Southern Investment Plan and employee and director stock plans. Additionally, in 2010, Southern Company issued 4.1 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of $143 million, net of $1 million in fees and commissions.

Shares Reserved

At December 31, 2011, a total of 107 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance shares units as discussed below). Of the total 107 million shares reserved, there were 47 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2011.

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2011, there were 6,955 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$ 1.80

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Southern Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject To Option	Weighted Average Exercise Price
Outstanding at December 31, 2010	50,711,586	$32.48
Granted	7,100,503	38.13
Exercised	(16,800,778)	31.44
Cancelled	(54,489)	33.43
Outstanding at December 31, 2011	**40,956,822**	**$33.88**
Exercisable at December 31, 2011	**26,539,300**	**$33.54**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $508 million and $338 million, respectively.

As of December 31, 2011, there was $7 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $22 million, $22 million, and $23 million, respectively, with the related tax benefit also recognized in income of $8 million, $9 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $155 million, $57 million, and $9 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $60 million, $22 million, and $4 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2011, 2010, and 2009 was $528 million, $198 million, and $19 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 908,341. During 2011, 894,858 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 83,601 performance share units were forfeited resulting in 1,719,598 unvested units outstanding at December 31, 2011.

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For the years ended December 31, 2011 and 2010, total compensation cost for performance share units recognized in income was $18 million and $9 million, respectively, with the related tax benefit also recognized in income of $7 million and $4 million, respectively. As of December 31, 2011, there was $29 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2011	2010	2009
		(in millions)	
As reported shares	**857**	832	795
Effect of options	**7**	5	1
Diluted shares	**864**	837	796

Stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive were 0.4 million and 13.1 million at December 31, 2011 and 2010, respectively. Assuming an average stock price of $42.67 (the highest exercise price of the anti-dilutive options outstanding in 2011), the effect of options would have been immaterial for the year ended December 31, 2011. Assuming an average stock price of $38.01 (the highest exercise price of the anti-dilutive options outstanding in 2010), the effect of options would have increased by 0.8 million shares for the year ended December 31, 2010.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2011, consolidated retained earnings included $6.0 billion of undistributed retained earnings of the subsidiaries.

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9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests, is $235 million and $237 million, respectively, per incident, but not more than an aggregate of $35 million per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, both companies have policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. Alabama Power and Georgia Power each purchase the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $43 million and $69 million, respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

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10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 14	$—	$ 14
Interest rate derivatives	—	13	—	13
Foreign currency derivatives	—	2	—	2
Nuclear decommissioning trusts: (a)				
Domestic equity	396	58	—	454
Foreign equity	124	48	—	172
U.S. Treasury and government agency securities	17	33	—	50
Municipal bonds	—	82	—	82
Corporate bonds	—	260	—	260
Mortgage and asset backed securities	—	151	—	151
Other investments	—	36	—	36
Cash equivalents and restricted cash	1,024	—	—	1,024
Other investments	3	50	14	67
Total	$1,564	$747	$14	$2,325
Liabilities:				
Energy-related derivatives	$ —	$245	$—	$ 245
Interest rate derivatives	—	33	—	33
Foreign currency derivatives	—	3	—	3
Total	$ —	$281	$—	$ 281

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

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As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 10	$—	$ 10
Interest rate derivatives	—	10	—	10
Foreign currency derivatives	—	3	—	3
Nuclear decommissioning trusts: [(a)]				
Domestic equity	604	60	—	664
U.S. Treasury and government agency securities	20	220	—	240
Municipal bonds	—	53	—	53
Corporate bonds	—	220	—	220
Mortgage and asset backed securities	—	119	—	119
Other investments	—	74	—	74
Cash equivalents and restricted cash	351	—	—	351
Other investments	9	51	19	79
Total	$984	$820	$ 19	$1,823
Liabilities:				
Energy-related derivatives	$ —	$206	$—	$ 206
Interest rate derivatives	—	1	—	1
Total	$ —	$207	$—	$ 207

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note 11 for additional information on how these derivatives are used.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

For fair value measurements of investments within the nuclear decommissioning trusts and rabbi trust funds, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts and rabbi trust funds with each security discriminately assigned a primary pricing source, based on similar characteristics.

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A market price secured from the primary source vendor is then used in the valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2011:	*(in millions)*			
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 32	None	Daily	1 to 3 days
Equity – commingled funds	48	None	Daily/Monthly	Daily/7 days
Other – commingled funds	25	None	Daily	Not applicable
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	1,024	None	Daily	Not applicable
As of December 31, 2010:				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 65	None	Daily	1 to 3 days
Other – commingled funds	67	None	Daily	Not applicable
Trust-owned life insurance	86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	351	None	Daily	Not applicable
Other:				
Money market funds	2	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds to comply with the NRC's regulations. The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds – commingled funds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

Alabama Power's nuclear decommissioning trust includes investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2011	**$20,272**	**$22,144**
2010	$19,356	$20,073

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. Southern Power has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2011, the net volume of energy-related derivative contracts for power and natural gas positions for the Southern Company system, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Power			Gas		
Net Purchased Megawatt-hours	Longest Hedge Date	Longest Non-Hedge Date	Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
(in millions)			*(in millions)*		
1	2012	2012	189	2017	2017

* million British thermal units

In addition to the volumes discussed in the table above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 9 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2012 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset with any difference representing ineffectiveness.

At December 31, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid*	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of forecasted debt					
	$ 100	3-month LIBOR	2.22%	January 2022	$ (1)
	300	3-month LIBOR	2.90%	December 2022	(17)
	300	3-month LIBOR	2.66%	April 2022	(15)
Fair value hedges of existing debt					
	350	4.15%	3-month LIBOR + 1.96% spread	May 2014	13
Total	$ 1,050				$ (20)

* Weighted Average

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For the year ended December 31, 2011, the Company had realized net gains of $5 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

Subsequent to December 31, 2011, Alabama Power settled $100 million of interest rate hedges related to the Series 2012A 4.10% Senior Notes issuance at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 is $15 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is recorded directly to earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2011, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)			*(in millions)*
Fair value hedges of firm commitments				
	EUR9.2	1.371 Dollars per Euro*	Various through March 2014	$ (1)
Derivatives not designated as hedges				
	EUR18.1	1.317 Dollars per Euro*	N/A	—
Total				$ (1)

* Weighted Average

During the year ended December 31, 2011, certain fair value hedges were de-designated. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company.

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Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 9**	$ 4	Liabilities from risk management activities	**$163**	$145
	Other deferred charges and assets	**5**	3	Other deferred credits and liabilities	**72**	55
Total derivatives designated as hedging instruments for regulatory purposes		**$14**	$ 7		**$235**	$200
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$—**	$—	Liabilities from risk management activities	**$ 1**	$ 1
Interest rate derivatives:	Other current assets	**6**	6	Liabilities from risk management activities	**33**	1
	Other deferred charges and assets	**7**	4	Other deferred credits and liabilities	**—**	—
Foreign currency derivatives:	Other current assets	**—**	2	Liabilities from risk management activities	**1**	—
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**—**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$13**	$13		**$ 35**	$ 2
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$—**	$ 2	Liabilities from risk management activities	**$ 9**	$ 5
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**—**	—
Foreign currency derivatives	Other current assets	**2**	—	Liabilities from risk management activities	**2**	—
Total derivatives not designated as hedging instruments		**$ 2**	$ 3		**$ 11**	$ 5
Total		**$29**	$23		**$281**	$207

All derivative instruments are measured at fair value. See Note 10 for additional information.

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At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	Balance Sheet Location	2011	2010	Balance Sheet Location	2011	2010
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(163)**	$(145)	Other regulatory liabilities, current	**$9**	$4
	Other regulatory assets, deferred	**(72)**	(55)	Other regulatory liabilities, deferred	**5**	3
Total energy-related derivative gains (losses)		**$(235)**	$(200)		**$14**	$7

For the year ended December 31, 2011, the pre-tax gains from interest rate derivatives designated as fair value hedging instruments on Southern Company's statement of income were $3 million. This amount was offset by changes in the fair value of the hedged debt.

For the year ended December 31, 2011, the pre-tax losses from foreign currency derivatives designated as fair value hedging instruments on Southern Company's statement of income, which include pre-tax losses arising from de-designated hedges prior to de-designation, were $4 million. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2011	2010	2009	Statements of Income Location	2011	2010	2009
		(in millions)				*(in millions)*	
Energy-related derivatives	**$ —**	$ 1	$(2)	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**(28)**	(3)	(5)	Interest expense, net of amounts capitalized	**(14)**	(25)	(46)
Foreign currency derivatives	**—**	1	—	Other operations and maintenance	**—**	1	—
				Other income (expense), net	**(1)**	—	—
Total	**$(28)**	$ (1)	$(7)		**$(15)**	$(24)	$(46)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was as follows:

Derivatives not Designated as Hedging Instruments	Unrealized Gain (Loss) Recognized in Income			
		Amount		
Derivative Category	Statements of Income Location	2011	2010	2009
			(in millions)	
Energy-related derivatives:	Wholesale revenues	**$ 2**	$ (2)	$ 5
	Fuel	**(9)**	1	(6)
	Purchased power	**1**	(1)	(4)
Total		**$(6)**	$(2)	$(5)

For the year ended December 31, 2011, the pre-tax losses from foreign currency derivatives not designated as hedging instruments were recorded as a regulatory asset and were not material to the Company.

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Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2011, the fair value of derivative liabilities with contingent features was $36 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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12. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Southern Power's revenues from sales to the traditional operating companies were $359 million, $371 million, and $544 million in 2011, 2010, and 2009, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2011							
Operating revenues	**$16,763**	**$1,236**	**$(412)**	**$17,587**	**$ 149**	**$ (79)**	**$17,657**
Depreciation and amortization	**1,576**	**124**	**—**	**1,700**	**16**	**1**	**1,717**
Interest income	**18**	**1**	**—**	**19**	**3**	**(1)**	**21**
Interest expense	**726**	**77**	**—**	**803**	**54**	**—**	**857**
Income taxes	**1,217**	**76**	**—**	**1,293**	**(74)**	**—**	**1,219**
Segment net income (loss)*	**2,052**	**162**	**—**	**2,214**	**(8)**	**(3)**	**2,203**
Total assets	**54,622**	**3,581**	**(127)**	**58,076**	**1,592**	**(401)**	**59,267**
Gross property additions	**4,589**	**255**	**—**	**4,844**	**9**	**—**	**4,853**
2010							
Operating revenues	$16,712	$1,130	$(468)	$17,374	$ 162	$ (80)	$17,456
Depreciation and amortization	1,376	119	—	1,495	18	—	1,513
Interest income	22	—	—	22	3	(1)	24
Interest expense	757	76	—	833	63	(1)	895
Income taxes	1,039	75	—	1,114	(89)	1	1,026
Segment net income (loss)*	1,860	131	—	1,991	(11)	(5)	1,975
Total assets	51,144	3,438	(128)	54,454	1,178	(600)	55,032
Gross property additions	4,029	405	—	4,434	9	—	4,443
2009							
Operating revenues	$15,304	$ 947	$(609)	$15,642	$ 165	$ (64)	$15,743
Depreciation and amortization	1,378	98	—	1,476	27	—	1,503
Interest income	21	—	—	21	3	(1)	23
Interest expense	749	85	—	834	71	—	905
Income taxes	902	86	—	988	(92)	—	896
Segment net income (loss)*	1,679	156	—	1,835	(193)	1	1,643
Total assets	48,403	3,043	(143)	51,303	1,223	(480)	52,046
Gross property additions	4,568	331	—	4,899	14	—	4,913

* After dividends on preferred and preference stock of subsidiaries

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
			(in millions)	
2011	**$15,071**	**$1,905**	**$611**	**$17,587**
2010	$14,791	$1,994	$589	$17,374
2009	13,307	1,802	533	15,642

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13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Per Common Share			
				Basic Earnings	Dividends	Trading Price Range	
						High	Low
		(in millions)					
March 2011	**$4,012**	**$ 854**	**$422**	**$0.50**	**$0.4550**	**$38.79**	**$36.51**
June 2011	**4,521**	**1,136**	**604**	**0.71**	**0.4725**	**40.87**	**37.43**
September 2011	**5,428**	**1,652**	**916**	**1.07**	**0.4725**	**43.09**	**35.73**
December 2011	**3,696**	**589**	**261**	**0.30**	**0.4725**	**46.69**	**41.00**
March 2010	$4,157	$ 922	$495	$0.60	$0.4375	$33.73	$30.85
June 2010	4,208	951	510	0.62	0.4550	35.45	32.04
September 2010	5,320	1,459	817	0.98	0.4550	37.73	33.00
December 2010	3,771	470	153	0.18	0.4550	38.62	37.10

Southern Company's business is influenced by seasonal weather conditions.

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	2011	2010	2009	2008	2007
Operating Revenues (in millions)	**$ 17,657**	$ 17,456	$ 15,743	$ 17,127	$ 15,353
Total Assets (in millions)	**$ 59,267**	$ 55,032	$ 52,046	$ 48,347	$ 45,789
Gross Property Additions (in millions)	**$ 4,853**	$ 4,443	$ 4,913	$ 4,122	$ 3,658
Return on Average Common Equity (percent)	**13.04**	12.71	11.67	13.57	14.60
Cash Dividends Paid Per Share of Common Stock	**$ 1.8725**	$ 1.8025	$ 1.7325	$ 1.6625	$ 1.595
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	**$ 2,203**	$ 1,975	$ 1,643	$ 1,742	$ 1,734
Earnings Per Share —					
Basic	**$ 2.57**	$ 2.37	$ 2.07	$ 2.26	$ 2.29
Diluted	**2.55**	2.36	2.06	2.25	2.28
Capitalization (in millions):					
Common stock equity	**$ 17,578**	$ 16,202	$ 14,878	$ 13,276	$ 12,385
Preferred and preference stock of subsidiaries	**707**	707	707	707	707
Redeemable preferred stock of subsidiaries	**375**	375	375	375	373
Long-term debt	**18,647**	18,154	18,131	16,816	14,143
Total (excluding amounts due within one year)	**$ 37,307**	$ 35,438	$ 34,091	$ 31,174	$ 27,608
Capitalization Ratios (percent):					
Common stock equity	**47.1**	45.7	43.6	42.6	44.9
Preferred and preference stock of subsidiaries	**1.9**	2.0	2.1	2.3	2.6
Redeemable preferred stock of subsidiaries	**1.0**	1.1	1.1	1.2	1.3
Long-term debt	**50.0**	51.2	53.2	53.9	51.2
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 20.32**	$ 19.21	$ 18.15	$ 17.08	$ 16.23
Market price per share:					
High	**$ 46.69**	$ 38.62	$ 37.62	$ 40.60	$ 39.35
Low	**35.73**	30.85	26.48	29.82	33.16
Close (year-end)	**46.29**	38.23	33.32	37.00	38.75
Market-to-book ratio (year-end) (percent)	**227.8**	199.0	183.6	216.6	238.8
Price-earnings ratio (year-end) (times)	**18.0**	16.1	16.1	16.4	16.9
Dividends paid (in millions)	**$ 1,601**	$ 1,496	$ 1,369	$ 1,279	$ 1,204
Dividend yield (year-end) (percent)	**4.0**	4.7	5.2	4.5	4.1
Dividend payout ratio (percent)	**72.7**	75.7	83.3	73.5	69.5
Shares outstanding (in thousands):					
Average	**856,898**	832,189	794,795	771,039	756,350
Year-end	**865,125**	843,340	819,647	777,192	763,104
Stockholders of record (year-end)	**155,198**	160,426*	92,799	97,324	102,903
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,809**	3,813	3,798	3,785	3,756
Commercial	**579**	580	580	594	600
Industrial	**15**	15	15	15	15
Other	**9**	9	9	8	6
Total	**4,412**	4,417	4,402	4,402	4,377
Employees (year-end)	**26,377**	25,940	26,112	27,276	26,472

* In July 2010, Southern Company changed its transfer agent from Southern Company Services, Inc. to Mellon Investor Services LLC. The change in the number of stockholders of record is primarily attributed to the calculation methodology used by Mellon Investor Services LLC.

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	2011	2010	2009	2008	2007
Operating Revenues (in millions):					
Residential	**$ 6,268**	$ 6,319	$ 5,481	$ 5,476	$ 5,045
Commercial	**5,384**	5,252	4,901	5,018	4,467
Industrial	**3,287**	3,097	2,806	3,445	3,020
Other	**132**	123	119	116	107
Total retail	**15,071**	14,791	13,307	14,055	12,639
Wholesale	**1,905**	1,994	1,802	2,400	1,988
Total revenues from sales of electricity	**16,976**	16,785	15,109	16,455	14,627
Other revenues	**681**	671	634	672	726
Total	**$ 17,657**	$ 17,456	$ 15,743	$ 17,127	$ 15,353
Kilowatt-Hour Sales (in millions):					
Residential	**53,341**	57,798	51,690	52,262	53,326
Commercial	**53,855**	55,492	53,526	54,427	54,665
Industrial	**51,570**	49,984	46,422	52,636	54,662
Other	**936**	943	953	934	962
Total retail	**159,702**	164,217	152,591	160,259	163,615
Wholesale sales	**30,345**	32,570	33,503	39,368	40,745
Total	**190,047**	196,787	186,094	199,627	204,360
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.75**	10.93	10.60	10.48	9.46
Commercial	**10.00**	9.46	9.16	9.22	8.17
Industrial	**6.37**	6.20	6.04	6.54	5.52
Total retail	**9.44**	9.01	8.72	8.77	7.72
Wholesale	**6.28**	6.12	5.38	6.10	4.88
Total sales	**8.93**	8.53	8.12	8.24	7.16
Average Annual Kilowatt-Hour Use Per Residential Customer	**13,997**	15,176	13,607	13,844	14,263
Average Annual Revenue Per Residential Customer	**$ 1,645**	$ 1,659	$ 1,443	$ 1,451	$ 1,349
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**43,555**	42,961	42,932	42,607	41,948
Maximum Peak-Hour Demand (megawatts):					
Winter	**34,617**	35,593	33,519	32,604	31,189
Summer	**36,956**	36,321	34,471	37,166	38,777
System Reserve Margin (at peak) (percent)	**19.2**	23.3	26.4	15.3	11.2
Annual Load Factor (percent)	**59.0**	62.2	60.6	58.7	57.6
Plant Availability (percent):					
Fossil-steam	**88.1**	91.4	91.3	90.5	90.5
Nuclear	**93.0**	92.1	90.1	91.3	90.8
Source of Energy Supply (percent):					
Coal	**48.7**	55.0	54.7	64.0	67.1
Nuclear	**15.0**	14.1	14.9	14.0	13.4
Hydro	**2.1**	2.5	3.9	1.4	0.9
Oil and gas	**28.0**	23.7	22.5	15.4	15.0
Purchased power	**6.2**	4.7	4.0	5.2	3.6
Total	**100.0**	100.0	100.0	100.0	100.0

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ALABAMA POWER COMPANY

FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2011 Annual Report

The management of Alabama Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

/s/ Charles D. McCrary
Charles D. McCrary
President and Chief Executive Officer

/s/ Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer

February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTANT FIRM

To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the "Company") (a wholly owned subsidiary of The Southern Company) as of December 31, 2011 and 2010, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-140 to II-186) referred to above present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 24, 2012

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2011 Annual Report

OVERVIEW

Business Activities

Alabama Power Company (the Company) operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than 1.4 million customers, the Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2011 Peak Season EFOR, excluding the impact of tornadoes in April 2011, was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2011 was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2011 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR — fossil/hydro	**4.80% or less**	**1.09%**
Net Income After Dividends on Preferred and Preference Stock	**$705 million**	**$708 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2011 net income after dividends on preferred and preference stock of $708 million increased $1 million (0.1%) over the prior year. The increase was due to a reduction in other operations and maintenance expenses, an increase in revenues under rate certificated new plant environmental (Rate CNP Environmental) associated with the completion of construction projects related to environmental mandates, and an increase in industrial kilowatt-hour (KWH) sales. The increases in net income were partially offset by reductions in wholesale revenues from sales to non-affiliates, decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, and a reduction in allowance for funds used during construction (AFUDC) equity.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2011 Annual Report

The Company's 2010 net income after dividends on preferred and preference stock of $707 million increased $37 million (5.5%) over the prior year. The increase was primarily due to increases in rates under the rate stabilization and equalization plan (Rate RSE) and the Rate CNP Environmental that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. The increases in retail revenues were partially offset by increases in operations and maintenance expenses, increases in depreciation and amortization, and reductions in wholesale revenues from sales to non-affiliates and AFUDC equity.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$5,702**	**$(274)**	$447
Fuel	**1,679**	**(172)**	27
Purchased power	**271**	**(9)**	(27)
Other operations and maintenance	**1,262**	**(156)**	207
Depreciation and amortization	**637**	**31**	61
Taxes other than income taxes	**339**	**7**	10
Total operating expenses	**4,188**	**(299)**	278
Operating income	**1,514**	**25**	169
Total other income and (expense)	**(289)**	**(9)**	(53)
Income taxes	**478**	**15**	79
Net income	**747**	**1**	37
Dividends on preferred and preference stock	**39**	**—**	—
Net income after dividends on preferred and preference stock	**$ 708**	**$ 1**	$ 37

Operating Revenues

Operating revenues for 2011 were $5.7 billion, reflecting a $274 million decrease from 2010. Details of operating revenues were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail — prior year	**$5,076**	$4,497
Estimated change in —		
Rates and pricing	**88**	310
Sales growth (decline)	**42**	(11)
Weather	**(147)**	199
Fuel and other cost recovery	**(87)**	81
Retail — current year	**4,972**	5,076
Wholesale revenues —		
Non-affiliates	**287**	465
Affiliates	**244**	236
Total wholesale revenues	**531**	701
Other operating revenues	**199**	199
Total operating revenues	**$5,702**	$5,976
Percent change	**(4.6)%**	8.1%

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2011 Annual Report

Retail revenues in 2011 were $5.0 billion. These revenues decreased $104 million (2.0%) in 2011 and increased $579 million (12.9%) in 2010 as compared to the prior period. The decrease was due to closer to normal weather in 2011 compared to 2010 and a reduction in fuel revenues when compared to the corresponding period in 2010. The decreases were partially offset by increased revenues associated with Rate CNP Environmental for the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under the Company's rate structure. The increase in 2010 was due to increases in rates and pricing under Rate RSE and Rate CNP Environmental that took effect January 2010, colder weather in the first and fourth quarters 2010, and warmer weather in the second and third quarters 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2011	2010	2009
		(in millions)	
Unit power sales —			
Capacity	**$ —**	$ 84	$158
Energy	**6**	95	207
Total	**6**	179	365
Other power sales —			
Capacity and other	**148**	148	133
Energy	**133**	138	122
Total	**281**	286	255
Total non-affiliated	**$287**	$465	$620

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to Florida utilities and sales to wholesale customers within the Company's service territory. Capacity revenues under unit power sales contracts reflect the recovery of fixed costs and a return on investment, and under these contracts, energy is generally sold at variable cost. Fluctuations in the prices of oil and natural gas, which are the primary fuel sources for unit power sales customers, influence changes in these energy sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings.

In May 2010, the long-term unit power sales contracts expired and the unit power energy sales and capacity revenues ceased, except for adjustments, which resulted in a reduction of wholesale revenues from sales to non-affiliates in 2011 and 2010. Beginning in June 2010, such capacity subject to the unit power sales contracts became available for retail service. In 2011, wholesale revenues from sales to non-affiliates decreased $178 million (38.3%) reflecting a $94 million decrease in revenue from energy sales and a $84 million decrease in capacity revenues. KWH sales decreased 46.9%, partially offset by a 15.3% increase in the price of energy. In 2010, wholesale revenues from sales to non-affiliates decreased $155 million (25.0%) reflecting a $96 million decrease in revenue from energy sales and a $59 million decrease in capacity revenues. KWH sales decreased 39.5%. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2011 Annual Report

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clauses. The changes in wholesale revenues from sales to affiliates for 2011 and 2010 were not material.

In 2011, other operating revenues were $199 million. The change from prior year revenues was not material. Other operating revenues increased $24 million (13.7%) in 2010 due to a $13 million increase in transmission sales and a $12 million increase in revenues from gas-fueled co-generation steam facilities as a result of greater sales volume. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2011 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in billions)				
Residential	**18.6**	**(8.7)%**	13.0 %	**0.6%**	(0.6)%
Commercial	**14.2**	**(3.7)**	3.8	**(0.6)**	(1.1)
Industrial	**21.7**	**5.1**	11.1	**5.1**	11.1
Other	**0.2**	**(0.9)**	(0.8)	**(0.9)**	(0.8)
Total retail	**54.7**	**(2.3)**	9.7	**2.0%**	3.5%
Wholesale —					
Non-affiliates	**4.6**	**(46.9)**	(39.5)		
Affiliates	**7.0**	**15.3**	(6.2)		
Total wholesale	**11.6**	**(21.3)**	(29.2)		
Total energy sales	**66.3**	**(6.2)%**	(1.6)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2011 were 2.3% less than in 2010. Energy sales were down in 2011 in the residential and commercial customer classes and up in the industrial customer class. Residential and commercial sales decreased 8.7% and 3.7%, respectively, due primarily to closer to normal weather in 2011 compared to 2010. Industrial sales increased 5.1% in 2011 as a result of increased customer demand, primarily in the primary metals, which includes fabricated pipe and metals, and chemicals sectors, due to a recovering economy.

Retail energy sales in 2010 were 9.7% greater than in 2009. Energy sales were up in 2010 across major classes of customers. Residential and commercial sales increased 13.0% and 3.8%, respectively, due primarily to significant weather-driven increases in KWH sales as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010. Industrial sales increased 11.1% in 2010 as a result of increased customer demand in most major sectors, including primary metals, chemicals, transportation, and textiles sectors, due to a recovering economy.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Fuel and purchased power expenses generally do not affect net income, since they are offset by fuel revenues under the Company's energy cost recovery rate (Rate ECR). The Company, along with the Alabama Public Service Commission (PSC), continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters — Fuel Cost Recovery" for additional information.

Details of the Company's electricity generated and purchased were as follows:

	2011	2010	2009
Total generation *(billions of KWHs)*	**64.8**	69.2	68.8
Total purchased power *(billions of KWHs)*	**4.7**	5.0	6.3
Sources of generation *(percent)* —			
Coal	**56**	61	58
Nuclear	**22**	19	20
Gas	**17**	15	13
Hydro	**5**	5	9
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.16**	3.02	3.02
Nuclear	**0.66**	0.60	0.56
Gas	**3.92**	4.47	5.24
Average cost of fuel, generated *(cents per net KWH)* *	**2.70**	2.76	2.79
Average cost of purchased power *(cents per net KWH)* **	**6.04**	6.42	6.05

* KWHs generated by hydro are excluded from the average cost of fuel, generated.

** Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $2.0 billion in 2011, a decrease of $181 million (8.5%) below the prior year costs. This decrease was primarily due to a $108 million decrease related to lower KWHs generated as a result of closer to normal weather in 2011 compared to 2010, a reduction in unit power energy sales, and a $56 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

Fuel and purchased power expenses were $2.1 billion in 2010. The increase over the prior year costs was not material.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. In 2011, purchased power from non-affiliates was $73 million. The increase from prior year costs was not material. In 2010, purchased power from non-affiliates decreased $16 million (18.2%) due to a 22.4% decrease in the amount of energy purchased, partially offset by a 6.7% increase in the average cost per KWH. In 2011 and 2010, purchased power from affiliates decreased $10 million and $11 million, respectively. The decreases from prior year costs were not material.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011. In early 2011, uranium prices continued the steady increase started during the second half of 2010. In March 2011, uranium prices fell sharply from the highs earlier in the year. After some price volatility in the second quarter 2011, the price leveled and remained relatively constant for the remainder of 2011. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2011; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

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Other Operations and Maintenance Expenses

In 2011, other operations and maintenance expenses decreased $156 million (11.0%) due to a $79 million decrease in transmission and distribution expenses related to vegetation management, reliability projects, and a reduction in accruals to the natural disaster reserve (NDR). Nuclear production expenses decreased $33 million primarily related to a change to the nuclear maintenance outage accounting process associated with the routine refueling activities, as approved by the Alabama PSC in August 2010. As a result, no nuclear maintenance outage expenses were recognized in 2011, reducing nuclear production expense by approximately $50 million compared to 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. In addition, the decrease in nuclear production expenses were partially offset by an increase in operations costs related to increases in labor. Administrative and general expenses decreased $28 million primarily related to injuries and damages expenses, affiliated service companies' expenses, and property insurance.

In 2010, other operations and maintenance expenses increased $207 million (17.1%) due to a $60 million increase in steam production expenses related to planned outage maintenance, environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and maintenance costs related to increases in labor and materials expenses, a $59 million increase in administrative and general expenses related to affiliated service companies' expenses, injuries and damages expenses, labor, and other general expenses, partially offset by a reduction in employee medical and other benefit-related expenses, a $57 million increase in transmission and distribution expenses related to vegetation management and an additional accrual to the NDR, and a $21 million increase in nuclear production expense related to scheduled outage costs and maintenance costs related to increases in labor.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" herein for additional information.

Depreciation and Amortization

Depreciation and amortization increased $31 million (5.1%) in 2011 and $61 million (11.2%) in 2010, primarily due to additions to property, plant, and equipment related to environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and transmission and distribution projects. See Note 3 to financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $7 million (2.1%) in 2011 and $10 million (3.1%) in 2010. The increases in 2011 and 2010 were primarily due to increases in state and municipal public utility license tax bases and an increase in local use tax.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $14 million (38.9%) in 2011 primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller. AFUDC equity decreased $43 million (54.4%) in 2010 from 2009 primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller partially offset by an increase in nuclear production projects. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Income Taxes

Income taxes increased $15 million (3.2%) in 2011 primarily due to higher pre-tax income, an increase in the tax expense associated with a decrease in AFUDC equity, and prior year tax return actualization.

Income taxes increased $79 million (20.6%) in 2010, primarily due to higher pre-tax income as compared to 2009, an increase in Alabama state taxes due to a decrease in the state deduction for federal income taxes paid, and an increase in the tax expense associated with a decrease in AFUDC equity and a decrease in the Internal Revenue Code of 1986, as amended, Section 199 production activities deduction.

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Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" and "FERC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power Company (Georgia Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power Company (Mississippi Power). On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2011 Annual Report

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million.

In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the Company had invested approximately $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $34 million, $130 million, and $526 million for 2011, 2010, and 2009, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $86 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$22	$20	$44

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The environmental costs that are known and estimable at this time are included in the Company's approved construction program and capital expenditures under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $5 billion to $7 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $1.2 billion from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $630 million over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	**2013**	**2014**
		(in millions)	
MATS rule	Up to $170	Up to $350	Up to $650
Proposed water and coal combustion byproducts rules	Up to $5	Up to $150	Up to $475
Total potential incremental environmental compliance investments	**Up to $175**	**Up to $500**	**Up to $1,125**

The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Company's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As of December 31, 2011, the Company had total generating capacity of approximately 12,222 megawatts (MWs), of which 6,579 MWs are coal-fired. Over the past several years, the Company has installed various pollution control technologies on its coal-fired units, including both selective catalytic reduction equipment and scrubbers on the seven largest coal units making up 4,812 MWs of the Company's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Company is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including on the units with existing pollution control technologies), and changing fuel sources for certain units.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, jointly owned with Georgia Power, is also developing an environmental compliance strategy for its 1,000 MWs of coal-fired generating capacity, which may result in unit retirements, installation of controls, or changing fuel source. The capacity of SEGCO's units is sold to the Company and Georgia Power through a power purchase agreement (PPA). See Note 4 to the Company's financial statements for additional information. The impact of SEGCO's compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements.

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Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company spent approximately $2.7 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. The 2008 standard is expected to result in designation of new nonattainment areas within the Company's service territory and could require additional reductions in NO_x emissions.

The EPA also regulates fine particulate matter emissions on an annual and 24-hour average basis. Although all areas within the Company's service territory have air quality levels that attain the current standard, the EPA has announced its intention to propose new, more stringent annual and 24-hour fine particulate matter standards in mid-2012.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Company's service territory were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. On April 6, 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by the Company, including units co-owned by Mississippi Power. The Company filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves the Company's appeal in its favor, the EPA's rescission will continue to affect the Company's operations.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets.

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The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the Company's facilities which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, and the MATS rule on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The ultimate outcome of these matters cannot be determined at this time.

Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs, as described above, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The Company currently operates six electric generating plants with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the State of Alabama has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

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The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described above, that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

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Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 45 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2011 greenhouse gas emissions on the same basis is approximately 45 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company continues to evaluate its future energy and emissions profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions. The Company is actively pursuing energy from resources with lower greenhouse gas emissions. The Company has entered into PPAs for the purchase of approximately 400 MWs of energy from renewable sources, including wind energy, some of which is pending regulatory approval.

FERC Matters

In 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued annual licenses for the Coosa River developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. Though the Coosa application remains pending before FERC, in March 2010, the FERC issued a new 30 year license to the Company for the Warrior River developments. In April 2010, the Smith Lake Improvement and Stakeholder Association filed a request for rehearing of the FERC order granting the new Warrior license. In May 2010, the FERC granted the rehearing request for the limited purpose of allowing the FERC additional time to consider the substantive issues raised in the request. The ultimate outcome of this matter cannot be determined at this time.

In 2006, the Company initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. The current Martin license will expire on June 8, 2013. On June 8, 2011, the Company filed an application with the FERC to relicense the Martin Dam Project. The ultimate outcome of this matter cannot be determined at this time.

In 2010, the Company initiated the process of developing an application to relicense the Holt Hydroelectric Project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed no later than August 31, 2013.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. The timing and final outcome of the Company's relicense applications cannot be determined at this time.

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PSC Matters

Retail Rate Adjustments

On July 12, 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information.

Rate RSE

Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, the Company agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, the Company had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that the Company leave in effect for 2012 the factors associated with the Company's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, the Company had an under recovered environmental clause balance of $11 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. On September 7, 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters — Environmental Statutes and Regulations — General" herein for additional information regarding environmental regulations.

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Fuel Cost Recovery

The Company has established fuel cost recovery rates under Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. On December 6, 2011, the Alabama PSC issued a consent order that the Company leave in effect the fuel cost recovery rates which began in April 2011 for 2012. Therefore, the Rate ECR factor as of January 1, 2012 remained at 2.681 cents per KWH. Effective with billings beginning in January 2013, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2011 and 2010, the Company had an under recovered fuel balance of approximately $31 million and $4 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred on April 27, 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC on July 12, 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balance in the NDR for the year ended December 31, 2011 was approximately $110 million. For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

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Nuclear Outage Accounting Order

In August 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Consequently, it is estimated there will be a positive cash flow benefit of between $75 million and $90 million in 2012.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded non-cash pre-tax pension income of approximately $21 million, $19 million, and $24 million in 2011, 2010, and 2009, respectively. Postretirement benefit costs for the Company were $11 million, $14 million, and $19 million in 2011, 2010, and 2009, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

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On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the Nuclear Regulatory Commission (NRC) is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time. See RISK FACTORS of the Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

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Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $6 million or less change in total benefit expense and an $81 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to add environmental equipment for existing generating units and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2013.

Net cash provided from operating activities in 2011 totaled $2.1 billion, an increase of $675 million as compared to 2010. The increase in cash provided from operating activities was primarily due to accrued taxes and deferred income taxes related to benefits associated with bonus depreciation, other current liabilities, accounts payable, and depreciation and amortization. Net cash provided from operating activities in 2010 totaled $1.4 billion, a decrease of $231 million as compared to 2009. The decrease in cash provided from operating activities was primarily due to receivables and other current liabilities related to less cash collections of regulatory clause revenues when compared to the prior year. This is partially offset by an increase in deferred income taxes related to bonus depreciation.

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Net cash used for investing activities totaled $1.0 billion for 2011 and 2010 and $1.2 billion for 2009 primarily due to gross property additions to utility plant of $1.0 billion, $0.9 billion, and $1.2 billion for 2011, 2010, and 2009, respectively. These additions were primarily related to environmental mandates, construction of transmission and distribution facilities, replacement of steam generation equipment, and purchases of nuclear fuel.

Net cash used for financing activities totaled $869 million in 2011 primarily due to issuances, redemptions, and a maturity of debt securities and payment of higher common stock dividends to Southern Company. Net cash used for financing activities totaled $600 million in 2010 primarily due to the payment of common stock dividends. Net cash used for financing activities totaled $35 million in 2009 primarily due to the redemption of debt securities and dividends paid in excess of debt issuances and cash raised from common stock sales. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2011 include increases in cash and cash equivalents and accumulated deferred income taxes of $190 million and $510 million, respectively, related to additional bonus depreciation, $304 million in property, plant, and equipment associated with routine property additions and nuclear fuel, and $319 million in other regulatory assets, deferred, partially offset by decreases of $134 million in prepaid expenses related to income taxes and $198 million in prepaid pension cost.

The Company's ratio of common equity to total capitalization, including short-term debt, was 43.9% in 2011 and 44.0% in 2010. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs which can fluctuate significantly due to the seasonality of the business.

At December 31, 2011, the Company had approximately $344 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires (a)						Executable Term-Loans	
2012	2013	2014	2016	Total	Unused	One Year	Two Years
		(in millions)					
$121	$35	$350	$800	$1,306	$1,306	$51	$—

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants.

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In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. At December 31, 2011, the Company had $794 million of outstanding pollution control revenue bonds requiring liquidity support.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$—	—%	$20	0.22%	$255
December 31, 2010:					
Commercial paper	$—	—%	$ 7	0.22%	$135

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In February 2011, the Company's $200 million Series HH 5.10% Senior Notes due February 1, 2011 matured.

In March 2011, the Company issued $250 million aggregate principal amount of Series 2011A 5.50% Senior Notes due March 15, 2041. The proceeds were used for general corporate purposes, including the Company's continuous construction program. The Company settled $200 million of interest rate hedges related to the Series 2011A 5.50% Senior Note issuance at a gain of approximately $4 million. The gain is being amortized to interest expense, in earnings, over 10 years.

In May 2011, the Company issued $200 million aggregate principal amount of Series 2011B 3.950% Senior Notes due June 1, 2021 and $250 million aggregate principal amount of Series 2011C 5.200% Senior Notes due June 1, 2041. The net proceeds were used by the Company for the redemption of $100 million aggregate principal amount of the Series GG 5 7/8% Senior Notes due February 1, 2046, $200 million aggregate principal amount of the Series II 5.875% Senior Notes due March 15, 2046, and $150 million aggregate principal amount of the Series JJ 6.375% Senior Notes due June 15, 2046.

In August 2011, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $300 million.

In September 2011, the Company redeemed approximately $4 million of The Industrial Development Board of the Town of Wilsonville Solid Waste Disposal Revenue Bonds (Plant Gaston), Series 2008.

In November 2011, the Company redeemed approximately $100 million aggregate principal amount of Series EE 5.75% Senior Notes due January 15, 2036.

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Subsequent to December 31, 2011, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program. In November 2011, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes in anticipation of this debt issuance. The notional amount of the swaps totaled $100 million and settled subsequent to December 31, 2011, at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

Subsequent to December 31, 2011, the Company announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012. Also, the Company announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $311 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $1 million of long-term variable interest rate exposure that has not been hedged at January 1, 2012 was .84%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $10 million at January 1, 2012. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel hedging program implemented per the guidelines of the Alabama PSC.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

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The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(38)**	$(44)
Contracts realized or settled	**37**	61
Current period changes [(a)]	**(47)**	(55)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(48)**	$(38)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was a decrease of $10 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, the Company had a net hedge volume of 38.9 million mmBtu with a weighted average swap contract cost approximately $1.45 per mmBtu above market prices, compared to a net hedge volume of 33.9 million mmBtu at December 31, 2010 with a weighted average swap contract cost approximately $1.14 per mmBtu above market prices. All the natural gas hedge gains and losses are recovered through the Company's fuel cost recovery clause.

At December 31, 2011 and 2010, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

		Fair Value Measurements December 31, 2011	
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(48)	(36)	(12)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(48)	$(36)	$(12)

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

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Capital Requirements and Contractual Obligations

The Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Over the next three years, the Company estimates spending $554 million on Plant Farley (including nuclear fuel), $932 million on distribution facilities, and $597 million on transmission additions. These base level capital investment amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $5 billion to $7 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule.

The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$915	$936	$1,102
Existing environmental statutes and regulations	22	20	44
Total construction program base level capital investment	**$937**	**$956**	**$1,146**
Potential incremental environmental compliance investments:			
MATS rule	Up to $170	Up to $350	Up to $650
Proposed water and coal combustion byproducts rules	Up to $5	Up to $150	Up to $475
Total potential incremental environmental compliance investments	**Up to $175**	**Up to $500**	**Up to $ 1,125**

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." In addition to the funds required for the Company's construction program, approximately $750 million will be required by the end of 2014 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

The Company has also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over an extended period will diminish internally funded capital for other purposes and may require the Company to seek capital from other sources. See Note 2 to the financial statements for additional information.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing (d)	Total
			(in millions)			
Long-term debt (a) —						
Principal	$ 500	$ 250	$ 254	$ 5,128	$ —	$ 6,132
Interest	279	495	481	3,812	—	5,067
Preferred and preference stock dividends (b)	39	79	79	—	—	197
Energy-related derivative obligations (c)	36	12	—	—	—	48
Interest rate derivative obligations (c)	18	—	—	—	—	18
Operating leases	21	24	13	2	—	60
Unrecognized tax benefits and interest (d)	6	—	—	—	28	34
Purchase commitments (e) —						
Capital (f)	755	1,818	—	—	—	2,573
Limestone (g)	16	34	24	38	—	112
Coal	1,347	1,881	430	463	—	4,121
Nuclear fuel	96	73	64	212	—	445
Natural gas (h)	246	411	284	124	—	1,065
Purchased power	31	83	93	419	—	626
Long-term service agreements (i)	24	35	36	—	—	95
Pension and other postretirement benefit plans (j)	20	33	—	—	—	53
Total	$3,434	$5,228	$1,758	$10,198	$ 28	$20,646

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2012, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $28 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2011, 2010, and 2009 were $1.3 billion, $1.4 billion, and $1.2 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $175 million, up to $500 million, and up to $1.1 billion for 2012, 2013, and 2014, respectively. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce SO_2 emissions from certain of its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, pending EPA civil action against the Company, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Alabama Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Revenues:			
Retail revenues	**$4,972**	$5,076	$4,497
Wholesale revenues, non-affiliates	**287**	465	620
Wholesale revenues, affiliates	**244**	236	237
Other revenues	**199**	199	175
Total operating revenues	**5,702**	5,976	5,529
Operating Expenses:			
Fuel	**1,679**	1,851	1,824
Purchased power, non-affiliates	**73**	72	88
Purchased power, affiliates	**198**	208	219
Other operations and maintenance	**1,262**	1,418	1,211
Depreciation and amortization	**637**	606	545
Taxes other than income taxes	**339**	332	322
Total operating expenses	**4,188**	4,487	4,209
Operating Income	**1,514**	1,489	1,320
Other Income and (Expense):			
Allowance for equity funds used during construction	**22**	36	79
Interest income	**18**	17	17
Interest expense, net of amounts capitalized	**(299)**	(303)	(298)
Other income (expense), net	**(30)**	(30)	(25)
Total other income and (expense)	**(289)**	(280)	(227)
Earnings Before Income Taxes	**1,225**	1,209	1,093
Income taxes	**478**	463	384
Net Income	**747**	746	709
Dividends on Preferred and Preference Stock	**39**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 708**	$ 707	$ 670

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Alabama Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$708**	$707	$670
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(5), $-, and $(2), respectively	**(9)**	—	(3)
Reclassification adjustment for amounts included in net income, net of tax of $(1), $(1), and $5, respectively	**(2)**	(2)	8
Total other comprehensive income (loss)	**(11)**	(2)	5
Comprehensive Income	**$697**	$705	$675

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
Alabama Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Activities:			
Net income	**$ 747**	$ 746	$ 709
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**749**	694	637
Deferred income taxes	**459**	410	(66)
Allowance for equity funds used during construction	**(22)**	(36)	(79)
Pension, postretirement, and other employee benefits	**(32)**	(15)	(8)
Pension and postretirement funding	**(9)**	(55)	(17)
Stock based compensation expense	**6**	5	4
Natural disaster reserve	**34**	52	55
Other, net	**(41)**	(27)	8
Changes in certain current assets and liabilities —			
-Receivables	**18**	(29)	310
-Fossil fuel stock	**47**	(1)	(77)
-Materials and supplies	**(33)**	(20)	(22)
-Other current assets	**(6)**	(4)	(16)
-Accounts payable	**11**	(54)	(19)
-Accrued taxes	**157**	(140)	24
-Accrued compensation	**(12)**	28	(32)
-Other current liabilities	**(25)**	(181)	193
Net cash provided from operating activities	**2,048**	1,373	1,604
Investing Activities:			
Property additions	**(977)**	(903)	(1,234)
Investment in restricted cash from pollution control bonds	**4**	—	(6)
Distribution of restricted cash from pollution control bonds	**13**	18	49
Nuclear decommissioning trust fund purchases	**(350)**	(237)	(245)
Nuclear decommissioning trust fund sales	**349**	236	244
Cost of removal net of salvage	**(28)**	(44)	(38)
Change in construction payables	**(9)**	(45)	26
Other investing activities	**9**	(12)	(25)
Net cash used for investing activities	**(989)**	(987)	(1,229)
Financing Activities:			
Increase (decrease) in notes payable, net	**—**	—	(25)
Proceeds —			
Common stock issued to parent	**—**	—	203
Capital contributions from parent company	**12**	28	24
Pollution control revenue bonds	**—**	—	79
Senior notes issuances	**700**	250	500
Redemptions —			
Pollution control revenue bonds	**(4)**	—	—
Senior notes	**(750)**	(250)	(250)
Payment of preferred and preference stock dividends	**(39)**	(39)	(39)
Payment of common stock dividends	**(774)**	(586)	(523)
Other financing activities	**(14)**	(3)	(4)
Net cash used for financing activities	**(869)**	(600)	(35)
Net Change in Cash and Cash Equivalents	**190**	(214)	340
Cash and Cash Equivalents at Beginning of Year	**154**	368	28
Cash and Cash Equivalents at End of Year	**$ 344**	$ 154	$ 368
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $9, $14 and $33 capitalized, respectively)	**$ 286**	$ 288	$ 255
Income taxes (net of refunds)	**(139)**	188	426

Noncash transactions - accrued property additions at year-end	**19**	28	74

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
At December 31, 2011 and 2010
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Assets	**2011**	2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 344**	$ 154
Restricted cash	**1**	18
Receivables —		
Customer accounts receivable	**332**	362
Unbilled revenues	**126**	153
Under recovered regulatory clause revenues	**—**	5
Other accounts and notes receivable	**35**	35
Affiliated companies	**79**	57
Accumulated provision for uncollectible accounts	**(10)**	(10)
Fossil fuel stock, at average cost	**344**	391
Materials and supplies, at average cost	**375**	346
Vacation pay	**59**	55
Prepaid expenses	**74**	208
Other regulatory assets, current	**44**	38
Other current assets	**11**	10
Total current assets	**1,814**	1,822
Property, Plant, and Equipment:		
In service	**20,809**	19,966
Less accumulated provision for depreciation	**7,344**	6,931
Plant in service, net of depreciation	**13,465**	13,035
Nuclear fuel, at amortized cost	**330**	283
Construction work in progress	**374**	547
Total property, plant, and equipment	**14,169**	13,865
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**62**	64
Nuclear decommissioning trusts, at fair value	**540**	552
Miscellaneous property and investments	**73**	71
Total other property and investments	**675**	687
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**532**	488
Prepaid pension costs	**59**	257
Deferred under recovered regulatory clause revenues	**48**	4
Other regulatory assets, deferred	**994**	675
Other deferred charges and assets	**186**	196
Total deferred charges and other assets	**1,819**	1,620
Total Assets	**$18,477**	$17,994

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
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Liabilities and Stockholder's Equity	2011	2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 500**	$ 200
Accounts payable —		
Affiliated	**203**	210
Other	**322**	273
Customer deposits	**85**	86
Accrued taxes —		
Accrued income taxes	**32**	2
Other accrued taxes	**34**	32
Accrued interest	**63**	63
Accrued vacation pay	**48**	45
Accrued compensation	**95**	99
Liabilities from risk management activities	**54**	31
Over recovered regulatory clause revenues	**—**	22
Other regulatory liabilities, current	**18**	—
Other current liabilities	**38**	41
Total current liabilities	**1,492**	1,104
Long-Term Debt (See accompanying statements)	**5,632**	5,987
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,257**	2,747
Deferred credits related to income taxes	**83**	85
Accumulated deferred investment tax credits	**149**	157
Employee benefit obligations	**343**	311
Asset retirement obligations	**553**	520
Other cost of removal obligations	**703**	701
Other regulatory liabilities, deferred	**156**	217
Other deferred credits and liabilities	**82**	87
Total deferred credits and other liabilities	**5,326**	4,825
Total Liabilities	**12,450**	11,916
Redeemable Preferred Stock (See accompanying statements)	**342**	342
Preference Stock (See accompanying statements)	**343**	343
Common Stockholder's Equity (See accompanying statements)	**5,342**	5,393
Total Liabilities and Stockholder's Equity	**$18,477**	$17,994
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CAPITALIZATION
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	2011	2010	**2011**	2010
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.68% at 1/1/12) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
5.10% due 2011	**—**	200		
4.85% due 2012	**500**	500		
5.80% due 2013	**250**	250		
5.20% due 2016	**200**	200		
3.375% to 6.375% due 2017-2047	**3,825**	3,675		
Total long-term notes payable	**4,775**	4,825		
Other long-term debt —				
Pollution control revenue bonds —				
0.75% to 5.00% due 2034	**367**	367		
Variable rate (0.07% at 1/1/12) due 2015	**54**	54		
Variable rates (0.03% to 0.17% at 1/1/12) due 2017-2038	**730**	734		
Total other long-term debt	**1,151**	1,155		
Unamortized debt premium (discount), net	**—**	1		
Total long-term debt (annual interest requirement — $279 million)	**6,132**	6,187		
Less amount due within one year	**500**	200		
Long-term debt excluding amount due within one year	**5,632**	5,987	**48.4%**	49.6%

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STATEMENTS OF CAPITALIZATION (continued)
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	2011	2010	**2011**	2010
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	**48**	48		
$1 par value — 5.20% to 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 12,000,000 shares: $25 stated value				
(annual dividend requirement — $18 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.9**	2.8
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 5.63% to 6.50%				
— 14,000,000 shares				
(non-cumulative) $25 stated value				
(annual dividend requirement — $21 million)	**343**	343	**2.9**	2.9
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,182**	2,156		
Retained earnings	**1,956**	2,022		
Accumulated other comprehensive income (loss)	**(18)**	(7)		
Total common stockholder's equity	**5,342**	5,393	**45.8**	44.7
Total Capitalization	**$11,659**	$12,065	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010, and 2009
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2008	25	$1,019	$2,091	$1,754	$ (10)	$4,854
Net income after dividends on preferred and preference stock	—	—	—	670	—	670
Issuance of common stock	5	203	—	—	—	203
Capital contributions from parent company	—	—	28	—	—	28
Other comprehensive income (loss)	—	—	—	—	5	5
Cash dividends on common stock	—	—	—	(523)	—	(523)
Other	1	—	—	—	—	—
Balance at December 31, 2009	31	1,222	2,119	1,901	(5)	5,237
Net income after dividends on preferred and preference stock	—	—	—	707	—	707
Issuance of common stock	—	—	—	—	—	—
Capital contributions from parent company	—	—	37	—	—	37
Other comprehensive income (loss)	—	—	—	—	(2)	(2)
Cash dividends on common stock	—	—	—	(586)	—	(586)
Balance at December 31, 2010	**31**	**1,222**	**2,156**	**2,022**	**(7)**	**5,393**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**708**	**—**	**708**
Capital contributions from parent company	**—**	**—**	**26**	**—**	**—**	**26**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(11)**	**(11)**
Cash dividends on common stock	**—**	**—**	**—**	**(774)**	**—**	**(774)**
Balance at December 31, 2011	**31**	**$1,222**	**$2,182**	**$1,956**	**$ (18)**	**$5,342**

The accompanying notes are an integral part of these financial statements.

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NOTES TO FINANCIAL STATEMENTS
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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $347 million, $371 million, and $325 million during 2011, 2010, and 2009, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $215 million, $218 million, and $183 million during 2011, 2010, and 2009, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $12 million in 2011, $11 million in 2010, and $10 million in 2009. See Note 4 for additional information.

Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2010 and 2009 totaled $15 million and $62 million, respectively. The Company also provided the fuel, at cost, associated with the PPA totaling $21 million and $63 million in 2010 and 2009, respectively. Due to the expiration of the Plant Harris PPA in May 2010, no purchased power costs or fuel costs were recognized in 2011. Additionally, the Company recorded no prepaid capacity expenses in 2011 or 2010 but recorded $8.3 million in 2009 which is included in other deferred charges and other assets in the balance sheets at December 31, 2009. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

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The Company has an agreement with Gulf Power under which the Company will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $85 million over the next three years. The Company expects to recover a majority of these costs through a tariff from Gulf Power over the next eleven years.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any significant services to or from affiliates in 2011, 2010, and 2009.

Also, see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO).

The traditional operating companies, including the Company and Southern Power, jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

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Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2011	2010	Note
	(in millions)		
Deferred income tax charges	**$ 532**	$ 488	(a,k)
Loss on reacquired debt	**84**	74	(b)
Vacation pay	**59**	55	(c,j)
Under/(over) recovered regulatory clause revenues	**47**	(13)	(d)
Fuel-hedging (realized and unrealized) losses	**48**	39	(e)
Other assets	**46**	30	(f)
Asset retirement obligations	**(35)**	(77)	(a)
Other cost of removal obligations	**(703)**	(701)	(a)
Deferred income tax credits	**(83)**	(85)	(a)
Fuel-hedging (realized and unrealized) gains	**(1)**	(1)	(e)
Mine reclamation and remediation	**(8)**	(10)	(g)
Nuclear outage	**38**	—	(d)
Natural disaster reserve	**(110)**	(127)	(h)
Other liabilities	**(20)**	(3)	(d)
Retiree benefit plans	**822**	569	(i,j)
Total assets (liabilities), net	**$ 716**	$ 238	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue, which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding five years.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(f) Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

(h) Utilized as storm restoration and potential reliability-related expenses are incurred, as approved by the Alabama PSC.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 and Note 5 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Included in the deferred income tax charges is $21 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years. See Note 5 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

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Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters — Fuel Cost Recovery" and "Retail Regulatory Matters — Rate CNP" for additional information.

The Company has a diversified base of customers. No single customer comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2011	2010
	(in millions)	
Generation	**$10,982**	$10,598
Transmission	**2,998**	2,826
Distribution	**5,517**	5,267
General	**1,300**	1,262
Plant acquisition adjustment	**12**	12
Total plant in service	**$20,809**	$19,965

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

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In August 2010, the Alabama PSC approved the Company's request to stop accruing for nuclear refueling outage costs in advance of the refueling outages when the most recent 18 month cycle ended in December 2010 and to begin deferring nuclear outage expenses. The amortization will begin after each outage has occurred and the associated outage expenses are known.

During 2011, the Company deferred $38 million of nuclear outage expenses associated with the fall 2011 outage and began the first 18-month amortization cycle for expenses in January 2012. The deferred nuclear outage expense balance of $38 million is included in the balance sheet as a regulatory asset. The second amortization cycle will begin in July 2012 for expenses associated with the spring 2012 outage.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2011, 3.3% in 2010, and 3.2% in 2009. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

During 2011, a depreciation study was completed based on information as of December 31, 2009. The study was approved by the FERC in October 2011 and was also provided to the Alabama PSC. The change in depreciation expense for 2012 associated with the approved rates is immaterial.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2011	2010
	(in millions)	
Balance at beginning of year	**$520**	$491
Liabilities incurred	**—**	—
Liabilities settled	**(2)**	(2)
Accretion	**35**	33
Cash flow revisions [(a)]	**—**	(2)
Balance at end of year	**$553**	$520

(a) Updated based on results from the 2009 Nuclear Interim Study

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Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. In addition, the NRC prohibits investments in securities of power reactor licensees. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

At December 31, 2011, investment securities in the Funds totaled $539 million consisting of equity securities of $382 million, debt securities of $146 million, and $11 million of other securities. At December 31, 2010, investment securities in the Funds totaled $552 million consisting of equity securities of $406 million, debt securities of $139 million, and $7 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $349 million, $236 million, and $244 million in 2011, 2010, and 2009, respectively, all of which were reinvested. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $6 million, of which $41 million related to realized gains and $51 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $65 million, of which $31 million related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $96 million, of which $80 million related to securities held in the Funds at December 31, 2009. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2011, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$540
Internal reserves	23
Total	$563

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Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2008 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2065

	(in millions)
Site study costs:	
Radiated structures	$1,060
Non-radiated structures	72
Total site study costs	$1,132

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%. The next site study is expected to be conducted in 2013.

As a result of license extensions, amounts previously contributed to the Funds are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.2% in 2011, 9.4% in 2010, and 9.2% in 2009. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 3.9% in 2011, 6.3% in 2010, and 14.9% in 2009.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

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Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate Natural Disaster Reserve (Rate NDR) charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the Natural Disaster Reserve (NDR) when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company’s ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve. See Note 3 under “Natural Disaster Reserve” herein for additional information.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Alabama PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in “Other” or shown separately as “Risk Management Activities”) and are measured at fair value. See Note 10 for additional information. Substantially all of the Company’s bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the “normal” scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

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The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2011.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income after dividends on preferred and preference stock, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entity

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this accounting guidance did not result in the Company consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2012, other postretirement trust contributions are expected to total approximately $8 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.52%	5.93%
Other postretirement benefit plans	**4.88**	5.41	5.84
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.39**	7.43	7.52

* Net of estimated investment management expenses of 30 basis points.

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The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2011 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$32	$(27)
Service and interest costs	2	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.8 billion at December 31, 2011 and $1.7 billion at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,779**	$1,675
Service cost	**43**	41
Interest cost	**96**	97
Benefits paid	**(88)**	(81)
Actuarial loss (gain)	**102**	47
Balance at end of year	**1,932**	1,779
Change in plan assets		
Fair value of plan assets at beginning of year	**1,933**	1,712
Actual return (loss) on plan assets	**32**	258
Employer contributions	**8**	44
Benefits paid	**(88)**	(81)
Fair value of plan assets at end of year	**1,885**	1,933
(Accrued liability) prepaid pension asset	**$ (47)**	$ 154

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At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $1.8 billion and $106 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in millions)	
Prepaid pension costs	**$ 59**	$257
Other regulatory assets, deferred	**727**	497
Other current liabilities	**(7)**	(7)
Employee benefit obligations	**(99)**	(96)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in millions)	
Prior service cost	**$ 33**	$ 41	**$ 7**
Net (gain) loss	**694**	456	**23**
Other regulatory assets, deferred	**$727**	$497	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2009	$549
Net (gain) loss	(42)
Change in prior service costs	1
Reclassification adjustments:	
Amortization of prior service costs	(9)
Amortization of net gain (loss)	(2)
Total reclassification adjustments	(11)
Total change	(52)
Balance at December 31, 2010	$497
Net (gain) loss	**243**
Change in prior service costs	**—**
Reclassification adjustments:	
Amortization of prior service costs	**(9)**
Amortization of net gain (loss)	**(4)**
Total reclassification adjustments	**(13)**
Total change	**230**
Balance at December 31, 2011	**$727**

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Components of net periodic pension cost (income) were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 43**	$ 41	$ 34
Interest cost	**96**	97	96
Expected return on plan assets	**(173)**	(168)	(164)
Recognized net (gain) loss	**4**	2	1
Net amortization	**9**	9	9
Net periodic pension cost (income)	**$ (21)**	$ (19)	$ (24)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2012	$ 95
2013	99
2014	102
2015	106
2016	110
2017 to 2021	604

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 454**	$ 461
Service cost	**5**	6
Interest cost	**24**	26
Benefits paid	**(27)**	(26)
Actuarial loss (gain)	**11**	(16)
Plan amendments	**—**	—
Retiree drug subsidy	**3**	3
Balance at end of year	**470**	454
Change in plan assets		
Fair value of plan assets at beginning of year	**323**	295
Actual return (loss) on plan assets	**5**	35
Employer contributions	**11**	16
Benefits paid	**(24)**	(23)
Fair value of plan assets at end of year	**315**	323
Accrued liability	**$(155)**	$(131)

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Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in millions)	
Regulatory assets	**$ 96**	$ 72
Employee benefit obligations	**(155)**	(131)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in millions)	
Prior service cost	**$ 26**	$ 30	**$ 4**
Net (gain) loss	**68**	37	**—**
Transition obligation	**2**	5	**2**
Regulatory assets	**$ 96**	$ 72	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2009	$108
Net (gain) loss	(29)
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(3)
Amortization of prior service costs	(4)
Amortization of net gain (loss)	—
Total reclassification adjustments	(7)
Total change	(36)
Balance at December 31, 2010	$72
Net (gain) loss	**31**
Change in prior service costs/transition obligation	**—**
Reclassification adjustments:	
Amortization of transition obligation	**(3)**
Amortization of prior service costs	**(4)**
Amortization of net gain (loss)	**—**
Total reclassification adjustments	**(7)**
Total change	**24**
Balance at December 31, 2011	**$ 96**

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Components of the other postretirement benefit plans' net periodic cost were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 5**	$ 6	$ 6
Interest cost	**24**	26	29
Expected return on plan assets	**(25)**	(25)	(24)
Net amortization	**7**	7	8
Net postretirement cost	**$ 11**	$ 14	$ 19

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2012	$ 30	$ (3)	$ 27
2013	32	(4)	28
2014	34	(4)	30
2015	35	(4)	31
2016	36	(5)	31
2017 to 2021	185	(28)	157

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	2011	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**—**	—
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	46%	**41%**	41%
International equity	11	**14**	16
Domestic fixed income	35	**38**	36
Special situations	1	**—**	—
Real estate investments	4	**4**	4
Private equity	3	**3**	3
Total	100%	**100%**	100%

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The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

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The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$320	$148	$ —	$ 468
International equity*	329	94	—	423
Fixed income:				
U.S. Treasury, government, and agency bonds	—	120	—	120
Mortgage- and asset-backed securities	—	37	—	37
Corporate bonds	—	232	1	233
Pooled funds	—	105	—	105
Cash equivalents and other	—	39	—	39
Real estate investments	61	—	217	278
Private equity	—	—	161	161
Total	$710	$775	$379	$ 1,864

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well diversified with no significant concentrations of risk.

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$358	$144	$ —	$ 502
International equity*	361	125	—	486
Fixed income:				
U.S. Treasury, government, and agency bonds	—	86	—	86
Mortgage- and asset-backed securities	—	70	—	70
Corporate bonds	—	168	1	169
Pooled funds	—	57	—	57
Cash equivalents and other	1	135	—	136
Real estate investments	52	—	191	243
Private equity	—	—	180	180
Total	$772	$785	$372	$1,929

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well diversified with no significant concentrations of risk.

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Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
			(in millions)	
Beginning balance	**$191**	**$180**	$166	$169
Actual return on investments:				
Related to investments held at year end	**16**	**(3)**	14	9
Related to investments sold during the year	**6**	**9**	3	3
Total return on investments	**22**	**6**	17	12
Purchases, sales, and settlements	**4**	**(25)**	8	(1)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$217**	**$161**	$191	$180

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Domestic equity*	$57	$ 8	$ —	$ 65
International equity*	17	5	—	22
Fixed income:				
U.S. Treasury, government, and agency bonds	—	9	—	9
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	160	—	160
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$78	$220	$19	$317

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well diversified with no significant concentrations of risk.

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As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$62	$ 7	$—	$ 69
International equity*	19	6	—	25
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5	—	5
Mortgage- and asset-backed securities	—	4	—	4
Corporate bonds	—	9	—	9
Pooled funds	—	3	—	3
Cash equivalents and other	—	24	—	24
Trust-owned life insurance	—	159	—	159
Real estate investments	3	—	10	13
Private equity	—	—	9	9
Total	$84	$217	$19	$320

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$10**	**$9**	$ 9	$10
Actual return on investments:				
Related to investments held at year end	**1**	**—**	1	—
Related to investments sold during the year	**—**	**—**	—	—
Total return on investments	**1**	**—**	1	—
Purchases, sales, and settlements	**—**	**(1)**	—	(1)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$11**	**$8**	$10	$ 9

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $18 million, $18 million, and $19 million, respectively.

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3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

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Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Nuclear Fuel Disposal Costs

The Company has a contract with the U.S., acting through the U.S. Department of Energy (DOE), that provides for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contract, and the Company is pursuing legal remedies against the government for breach of contract.

In 2007, the U.S. Court of Federal Claims awarded the Company approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In 2008, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to the Company. On July 12, 2011, the court entered final judgment in favor of the Company and awarded the Company approximately $17 million. In April 2012, the award will be credited to cost of service for the benefit of customers.

In 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim) due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2011 for the second claim. The final outcome of these matters cannot be determined at this time.

An on-site dry spent fuel storage facility at Plant Farley is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

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Retail Regulatory Matters

Retail Rate Adjustments

On July 12, 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information.

Rate RSE

Rate stabilization and equalization plan (Rate RSE) adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, the Company agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010, of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, the Company had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that the Company leave in effect for 2012 the factors associated with the Company's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, the Company had an under recovered environmental clause balance of $11 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. On September 7, 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

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Fuel Cost Recovery

The Company has established fuel cost recovery rates under the Company's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt-hour (KWH). On December 6, 2011, the Alabama PSC issued a consent order that the Company leave in effect the fuel cost recovery rates which began in April 2011 for 2012. Therefore, the Rate ECR factor as of January 1, 2012 remained at 2.681 cents per KWH. Effective with billings beginning in January 2013, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2011 and 2010, the Company had an under recovered fuel balance of approximately $31 million and $4 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has discretionary authority to accrue certain additional amounts as circumstances warrant.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows the Company to make additional accruals to the NDR. The order also allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred on April 27, 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC on July 12, 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balance in the NDR for the year ended December 31, 2011 was approximately $110 million. For the year ended December 31, 2010, the Company accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

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Nuclear Outage Accounting Order

In August 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the new order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the new accounting order is that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be amortized to nuclear operations and maintenance expenses over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense and a return on equity. The Company's share of purchased power totaled $142 million in 2011, $101 million in 2010, and $82 million in 2009, and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2011, the capitalization of SEGCO consisted of $87 million of equity and $75 million of long-term debt on which the annual interest requirement is $3 million. SEGCO paid dividends of $15 million in 2011, $5 million in 2010, and none in 2009, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2011 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Amount of Investment	Accumulated Depreciation
			(in millions)	
Greene County	500	60.00%(1)	$ 148	$ 78
Plant Miller				
Units 1 and 2	1,320	91.84%(2)	1,389	510

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with PowerSouth.

At December 31, 2011, the Company's portion of Plant Miller construction work in progress was $7.4 million.

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

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5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Tennessee. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in millions)	
Federal —			
Current	**$ 20**	$ 52	$ 374
Deferred	**377**	333	(41)
	$ 397	$ 385	$ 333
State —			
Current	**$ (1)**	$ 1	$ 76
Deferred	**82**	77	(25)
	81	78	51
Total	**$ 478**	$ 463	$ 384

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,820**	$2,415
Property basis differences	**439**	396
Premium on reacquired debt	**33**	31
Pension and other benefits	**217**	210
Fuel clause under recovered	**26**	10
Regulatory assets associated with employee benefit obligations	**343**	239
Regulatory assets associated with asset retirement obligations	**233**	220
Other	**94**	85
Total	**4,205**	3,606
Deferred tax assets:		
Federal effect of state deferred taxes	**186**	177
State effect of federal deferred taxes	**—**	50
Unbilled revenue	**38**	41
Storm reserve	**38**	41
Pension and other benefits	**373**	264
Other comprehensive losses	**14**	8
Asset retirement obligations	**233**	220
Other	**97**	87
Total	**979**	888
Total deferred tax liabilities, net	**3,226**	2,718
Portion included in current assets (liabilities), net	**31**	29
Accumulated deferred income taxes	**$3,257**	$2,747

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At December 31, 2011, the Company's tax-related regulatory assets to be recovered from customers were $532 million. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, the Company deferred $21 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The Company will amortize the regulatory asset to income tax expense over the average remaining service period which may range up to 15 years, as approved by the Alabama PSC.

At December 31, 2011, the Company's tax-related regulatory liabilities to be credited to customers were $83 million. These liabilities are attributable to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in each of 2011, 2010, and 2009. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had been utilized.

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.3**	4.2	3.0
Non-deductible book depreciation	**0.8**	0.8	0.8
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.1)	(0.2)
AFUDC-equity	**(0.6)**	(1.0)	(2.5)
Production activities deduction	**—**	—	(0.8)
Other	**(0.4)**	(0.6)	(0.2)
Effective income tax rate	**39.0%**	38.3%	35.1%

State income tax, net of federal deduction in 2011, was not materially different when compared to 2010. In 2010, state income tax, net of federal deduction increased due to a decrease in the state deduction for federal income taxes paid, which is a result of increased bonus depreciation and pension contributions.

The tax benefit of AFUDC-equity decreased in 2011 and 2010 from prior years due to a decrease in AFUDC, resulting from the completion of construction projects related to environmental mandates at generating facilities. See Note 1 under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

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Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $11 million, resulting in a balance of $32 million as of December 31, 2011.

Changes during the year in unrecognized tax benefits were as follows:

	2011	2010	2009
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 43**	$ 6	$ 3
Tax positions from current periods	**6**	6	2
Tax positions from prior periods	**(17)**	31	1
Reductions due to settlements	**—**	—	—
Reductions due to expired statute of limitations	**—**	—	—
Balance at end of year	**$ 32**	$43	$ 6

The tax positions from current periods for 2011 relate primarily to the tax accounting method change for repairs-generation assets. The tax positions decrease from prior periods for 2011 relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in millions)	
Tax positions impacting the effective tax rate	**$ 5**	$ 6	$ 6
Tax positions not impacting the effective tax rate	**27**	37	—
Balance of unrecognized tax benefits	**$ 32**	$43	$ 6

The tax positions impacting the effective tax rate for 2011 primarily relate to the production activities deduction tax position. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See "Tax Method of Accounting for Repairs" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in millions)	
Interest accrued at beginning of year	**$1.5**	$0.3	$0.3
Interest reclassified due to settlements	**—**	—	—
Interest accrued during the year	**0.4**	1.2	—
Balance at end of year	**$1.9**	$1.5	$0.3

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

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Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $141 million for the Company. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2011 and December 31, 2010, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2011 and 2010, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entity" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2011 and 2010, the Company had scheduled maturities of senior notes due within one year totaling $500 million and $200 million, respectively.

Maturities of senior notes and pollution control revenue bonds through 2016 applicable to total long-term debt are as follows: $500 million in 2012; $250 million in 2013; $54 million in 2015; and $200 million in 2016. There are no scheduled maturities in 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2011. In 2011, the Company redeemed approximately $4 million of The Industrial Development Board of the Town of Wilsonville Solid Waste Disposal Revenue Bonds (Plant Gaston), Series 2008. The amount of tax-exempt pollution control revenue bonds outstanding at both December 31, 2011 and 2010 was $1.2 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Subsequent to December 31, 2011, the Company announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

Senior Notes

The Company issued a total of $700 million of unsecured senior notes in 2011. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program, and to redeem $100 million aggregate principal amount of the Series GG 5-7/8% Senior Notes due February 1, 2046, $200 million aggregate principal amount of the Series II 5.875% Senior Notes due March 15, 2046, $150 million aggregate principal amount of the Series JJ 6.375% Senior Notes due June 15, 2046.

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Also during 2011, the Company redeemed approximately $100 million aggregate principal amount of Series EE 5.75% Senior Notes due January 15, 2036.

At both December 31, 2011 and 2010, the Company had $4.8 billion of senior notes outstanding. These senior notes are effectively subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2011.

Subsequent to December 31, 2011, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2011, the Company announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012.

Preferred, Preference, and Common Stock

In 2011, the Company issued no new shares of preferred stock, preference stock, or common stock.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution.

The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. Certain series of the Company's preference stock are subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date and the other series of preference stock are subject to redemption at a price equal to the stated capital. Certain series of the Company's preferred stock are subject to redemption at the option of the Company on or after a specified date. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/Stated Capital Per Share	Shares Outstanding	First Call Date	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	*	$103.23
4.72% Preferred Stock	$100	50,000	*	$102.18
4.64% Preferred Stock	$100	60,000	*	$103.14
4.60% Preferred Stock	$100	100,000	*	$104.20
4.52% Preferred Stock	$100	50,000	*	$102.93
4.20% Preferred Stock	$100	135,115	*	$105.00
5.83% Class A Preferred Stock	$ 25	1,520,000	08/1/2008	Stated Capital
5.20% Class A Preferred Stock	$ 25	6,480,000	08/1/2008	Stated Capital
5.30% Class A Preferred Stock	$ 25	4,000,000	04/1/2009	Stated Capital
5.625% Preference Stock	$ 25	6,000,000	01/1/2012	Stated Capital
6.450% Preference Stock	$ 25	6,000,000	*	**
6.500% Preference Stock	$ 25	2,000,000	*	**

* Redemption permitted any time after issuance
** Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; After 10/01/2017: Stated Capital

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Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million as of December 31, 2011. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

At December 31, 2011, committed credit arrangements with banks were as follows:

Expires (a)						Executable Term-Loans	
2012	2013	2014	2016	Total	Unused	One Year	Two Years
		(in millions)					
$121	$35	$350	$800	$1,306	$ 1,306	$51	$—

(a) No credit arrangements expire in 2015.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. During 2011, the Company remarketed $120 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support is $794 million as of December 31, 2011.

Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2011, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. The cross default provisions are restricted to indebtedness (including guaranteed obligations) of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$ —	—	$20	0.22%	$255
December 31, 2010:					
Commercial paper	$ —	—	$ 7	0.22%	$135

(a) Average and maximum amounts are based upon daily balances during the period.

At December 31, 2011, the Company had regulatory approval to have outstanding up to $2.3 billion of short-term borrowings.

7. COMMITMENTS

Construction Program

The approved construction program of the Company is currently estimated to include a base level investment of $0.9 billion for 2012, $1.0 billion for 2013, and $1.1 billion for 2014. Over the next three years, the Company estimates spending $554 million on Plant Farley (including nuclear fuel), $932 million on distribution facilities, and $597 million on transmission additions. These base level investment amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $22 million, $20 million, and $44 million for 2012, 2013, and 2014, respectively. These base level environmental expenditures do not include potential incremental environmental compliance investments to comply with the EPA’s final Mercury and Air Toxics Standards rule and the proposed water and coal combustion byproducts rules. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2011, significant purchase commitments were outstanding in connection with the continuous construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

The Company has entered into long-term service agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. The LTSAs provide that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each LTSA.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these LTSAs for facilities owned are currently estimated at $95 million over the remaining life of the LTSAs, which are currently estimated to range up to five years. However, the LTSAs contain various cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

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Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 2.2 million tons, equating to approximately $112 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $16 million in 2012, $17 million in 2013, $17 million in 2014, $12 million in 2015, and $12 million in 2016.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2011. Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2012	$ 246	$1,347	$ 96
2013	237	1,047	30
2014	174	834	43
2015	145	284	43
2016	139	146	21
2017 and thereafter	124	463	212
Total commitments	$1,065	$4,121	$445

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $95 million in 2011, $79 million in 2010, and $78 million in 2009.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of capacity and energy. Total estimated minimum long-term obligations at December 31, 2011 were as follows:

	Commitments
	Non-Affiliated
	(in millions)
2012	$ 31
2013	39
2014	44
2015	46
2016	47
2017 and thereafter	419
Total commitments	$626

Certain PPAs reflected in the table are accounted for as operating leases.

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Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses amounted to $23 million in 2011, $25 million in 2010, and $27 million in 2009. Of these amounts, $18 million, $20 million, and $20 million for 2011, 2010, and 2009, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2012	$19	$ 2	$21
2013	15	1	16
2014	7	1	8
2015	6	1	7
2016	5	1	6
2017 and thereafter	2	—	2
Total *	$54	$ 6	$60

* Total does not include payments related to a non-affiliated PPA that is accounted for as an operating lease. Obligations related to this agreement are included in the above purchased power commitments table.

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. The Company's maximum obligations under these leases are $1 million in 2012, $39 million in 2013, $8 million in 2014, $5 million in 2015, $4 million in 2016, and none in 2017. Upon termination of the leases, the Company has the option to negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2011, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2011, there were 1,242 current and former employees of the Company participating in the stock option program and there were 47 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

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The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2011	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

The Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2010	8,744,984	$32.35
Granted	1,073,781	38.02
Exercised	(2,622,513)	31.15
Cancelled	(4,466)	35.95
Outstanding at December 31, 2011	**7,191,786**	**$33.63**
Exercisable at December 31, 2011	**4,724,956**	**$33.36**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $91 million and $61 million, respectively.

As of December 31, 2011, there was $1 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $3 million, $3 million, and $4 million, respectively, with the related tax benefit also recognized in income of $1 million, $1 million, and $1 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $23 million, $12 million, and $2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $9 million, $4 million, and $1 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

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The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 151,802. During 2011, 142,822 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 6,904 performance share units were forfeited resulting in 287,720 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units recognized in income was $3 million and $1 million, respectively, with the related tax benefit also recognized in income of $1 million and $1 million, respectively. As of December 31, 2011, there was $5 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $235 million per incident but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.3 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $43 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Nuclear decommissioning trusts: [a]				
Domestic equity	$253	$ 57	$—	$310
Foreign equity	24	48	—	72
U.S. Treasury and government agency securities	17	8	—	25
Corporate bonds	—	93	—	93
Mortgage and asset backed securities	—	28	—	28
Other investments	—	11	—	11
Cash equivalents and restricted cash	209	—	—	209
Total	$503	$245	$—	$748
Liabilities:				
Energy-related derivatives	$ —	$ 48	$—	$ 48
Interest rate derivatives	—	18	—	18
Total	$ —	$ 66	$—	$ 66

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

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NOTES (continued)
Alabama Power Company 2011 Annual Report

As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 2	$—	$ 2
Nuclear decommissioning trusts: [(a)]				
Domestic equity	347	59	—	406
U.S. Treasury and government agency securities	20	7	—	27
Corporate bonds	—	82	—	82
Mortgage and asset backed securities	—	30	—	30
Other investments	—	7	—	7
Cash equivalents and restricted cash	109	—	—	109
Total	$476	$187	$—	$663
Liabilities:				
Energy-related derivatives	$ —	$ 40	$—	$ 40

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate (LIBOR) interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then used in the valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

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Alabama Power Company 2011 Annual Report

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2011:	*(in millions)*			
Nuclear decommissioning trusts:				
Equity-commingled funds	$ 48	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	209	None	Daily	Not applicable
As of December 31, 2010:				
Nuclear decommissioning trusts:				
Trust-owned life insurance	$ 86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	109	None	Daily	Not applicable

The nuclear decommissioning trust includes investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company’s investment in the money market funds.

As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2011	**$6,132**	**$6,874**
2010	$6,187	$6,463

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company’s policies in areas such as counterparty exposure and risk management practices. The Company’s policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

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Alabama Power Company 2011 Annual Report

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2011, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Gas	
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)		
39	2017	—

* mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2012 are immaterial.

Interest Rate Derivatives

The Company also enters into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

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At December 31, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of forecasted debt					
	$ 100	3M LIBOR	2.22%*	January 2022	$ (1.6)
	300	3M LIBOR	2.90%*	December 2022	(16.6)
Total	$ 400				$ (18.2)

* Weighted Average Rate

For the year ended December 31, 2011, the Company had realized net gains of $4 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

Subsequent to December 31, 2011, the Company settled $100 million of interest rate hedges related to the Series 2012A 4.10% Senior Notes issuance at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

The estimated pre-tax gains that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 is $0.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$—**	$ 1	Liabilities from risk management activities	**$36**	$31
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**12**	9
Total derivatives designated as hedging instruments for regulatory purposes		**$—**	$ 2		**$48**	$40
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$—**	$—	Liabilities from risk management activities	**$18**	$—
Total		**$—**	$ 2		**$66**	$40

All derivative instruments are measured at fair value. See Note 10 for additional information.

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NOTES (continued)
Alabama Power Company 2011 Annual Report

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$36**	$(31)	Other current liabilities	**$—**	$1
	Other regulatory assets, deferred	**12**	(9)	Other regulatory liabilities, deferred	**—**	1
Total energy-related derivative gains (losses)		**$48**	$(40)		**$—**	$2

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in millions)				*(in millions)*	
Interest rate derivatives	**$(14)**	$—	$(5)	Interest expense, net of amounts capitalized	**$3**	$3	$(12)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2011, the fair value of derivative liabilities with contingent features was $10 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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NOTES (continued)
Alabama Power Company 2011 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2011	**$1,320**	**$329**	**$152**
June 2011	**1,440**	**404**	**190**
September 2011	**1,671**	**523**	**264**
December 2011	**1,271**	**258**	**102**
March 2010	$1,495	$399	$203
June 2010	1,462	389	190
September 2010	1,706	497	259
December 2010	1,313	204	55

The Company's business is influenced by seasonal weather conditions.

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011
Alabama Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions)	**$ 5,702**	$ 5,976	$ 5,529	$ 6,077	$ 5,360
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 708**	$ 707	$ 670	$ 616	$ 580
Cash Dividends on Common Stock (in millions)	**$ 774**	$ 586	$ 523	$ 491	$ 465
Return on Average Common Equity (percent)	**13.19**	13.31	13.27	13.30	13.73
Total Assets (in millions)	**$ 18,477**	$ 17,994	$ 17,524	$ 16,536	$ 15,747
Gross Property Additions (in millions)	**$ 1,016**	$ 956	$ 1,323	$ 1,533	$ 1,203
Capitalization (in millions):					
Common stock equity	**$ 5,342**	$ 5,393	$ 5,237	$ 4,854	$ 4,411
Preference stock	**343**	343	343	343	343
Redeemable preferred stock	**342**	342	342	342	340
Long-term debt	**5,632**	5,987	6,082	5,605	4,750
Total (excluding amounts due within one year)	**$ 11,659**	$ 12,065	$ 12,004	$ 11,144	$ 9,844
Capitalization Ratios (percent):					
Common stock equity	**45.8**	44.7	43.6	43.6	44.8
Preference stock	**2.9**	2.9	2.9	3.1	3.5
Redeemable preferred stock	**2.9**	2.8	2.8	3.0	3.4
Long-term debt	**48.4**	49.6	50.7	50.3	48.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,231,574**	1,235,128	1,229,134	1,220,046	1,207,883
Commercial	**196,270**	197,336	198,642	211,119	216,830
Industrial	**5,844**	5,770	5,912	5,906	5,849
Other	**746**	782	780	775	772
Total	**1,434,434**	1,439,016	1,434,468	1,437,846	1,431,334
Employees (year-end)	**6,632**	6,552	6,842	6,997	6,980

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011 (continued)
Alabama Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions):					
Residential	**$ 2,144**	$ 2,283	$ 1,962	$ 1,998	$ 1,834
Commercial	**1,495**	1,535	1,430	1,459	1,314
Industrial	**1,306**	1,231	1,080	1,381	1,238
Other	**27**	27	25	24	21
Total retail	**4,972**	5,076	4,497	4,862	4,407
Wholesale — non-affiliates	**287**	465	620	712	627
Wholesale — affiliates	**244**	236	237	308	144
Total revenues from sales of electricity	**5,503**	5,777	5,354	5,882	5,178
Other revenues	**199**	199	175	195	182
Total	**$ 5,702**	$ 5,976	$ 5,529	$ 6,077	$ 5,360
Kilowatt-Hour Sales (in millions):					
Residential	**18,650**	20,417	18,071	18,380	18,874
Commercial	**14,173**	14,719	14,186	14,551	14,761
Industrial	**21,666**	20,622	18,555	22,075	22,806
Other	**214**	216	218	201	201
Total retail	**54,703**	55,974	51,030	55,207	56,642
Wholesale — non-affiliates	**4,330**	8,655	14,317	15,204	15,769
Wholesale — affiliates	**7,211**	6,074	6,473	5,256	3,241
Total	**66,244**	70,703	71,820	75,667	75,652
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.50**	11.18	10.86	10.87	9.71
Commercial	**10.55**	10.43	10.08	10.03	8.90
Industrial	**6.03**	5.97	5.82	6.26	5.43
Total retail	**9.09**	9.07	8.81	8.81	7.78
Wholesale	**4.60**	4.76	4.12	4.99	4.06
Total sales	**8.31**	8.17	7.45	7.77	6.84
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,138**	16,570	14,716	15,162	15,696
Residential Average Annual Revenue Per Customer	**$ 1,740**	$ 1,853	$ 1,597	$ 1,648	$ 1,525
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,553**	11,349	10,701	10,747	10,144
Summer	**11,500**	11,488	10,870	11,518	12,211
Annual Load Factor (percent)	**60.6**	62.6	59.8	60.9	59.4
Plant Availability (percent):					
Fossil-steam	**88.7**	92.9	88.5	90.1	88.2
Nuclear	**94.7**	88.4	93.3	94.1	87.5
Source of Energy Supply (percent):					
Coal	**52.5**	56.6	53.4	58.5	60.9
Nuclear	**20.8**	17.7	18.6	17.8	16.5
Hydro	**4.6**	5.0	7.9	2.9	1.8
Gas	**15.3**	14.0	11.8	9.2	8.7
Purchased power —					
From non-affiliates	**0.9**	1.6	2.0	2.9	1.8
From affiliates	**5.9**	5.1	6.3	8.7	10.3
Total	**100.0**	100.0	100.0	100.0	100.0

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GEORGIA POWER COMPANY

FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2011 Annual Report

The management of Georgia Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

/s/ W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer

/s/ Ronnie R. Labrato
Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer

February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of The Southern Company) as of December 31, 2011 and 2010, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-222 to II-270) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 24, 2012

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2011 Annual Report

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. The Company is currently constructing two new nuclear and two new combined cycle generating units. A third combined cycle generating unit went into commercial operation on December 28, 2011. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. In December 2010, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), including a base rate increase of approximately $562 million effective January 1, 2011, and additional increases in 2012 and 2013.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than two million customers, the Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2011 fossil/hydro Peak Season EFOR of 1.55% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The 2011 performance was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2011 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR — fossil/hydro	**4.80% or less**	**1.55%**
Net Income After Dividends on Preferred and Preference Stock	**$1.1 billion**	**$1.1 billion**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

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Earnings

The Company's 2011 net income after dividends on preferred and preference stock totaled $1.1 billion representing a $195 million, or 20.5%, increase over the previous year. The increase was due primarily to increases in retail base revenues, effective January 1, 2011, as authorized under the 2010 ARP and the financing costs associated with the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4), collected through the Nuclear Construction Cost Recovery (NCCR) tariff, partially offset by closer to normal weather in 2011 compared to 2010, higher non-fuel operating expenses, lower allowance for funds used during construction (AFUDC) equity, and higher income taxes. The increase was also due to a reduction in interest expense arising from the settlement of tax litigation with the Georgia Department of Revenue (DOR), partially offset by a decrease in the amortization of the regulatory liability related to other cost of removal obligations.

The Company's 2010 net income after dividends on preferred and preference stock totaled $950 million representing a $136 million, or 16.7%, increase over the previous year. The increase was due primarily to higher residential base revenues resulting from colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 and increased amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC, partially offset by increases in operations and maintenance expenses. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$8,800**	**$ 451**	$657
Fuel	**2,789**	**(313)**	385
Purchased power	**1,103**	**157**	(33)
Other operations and maintenance	**1,777**	**43**	240
Depreciation and amortization	**715**	**157**	(97)
Taxes other than income taxes	**369**	**25**	27
Total operating expenses	**6,753**	**69**	522
Operating income	**2,047**	**382**	135
Allowance for equity funds used during construction	**96**	**(51)**	50
Interest expense, net of amounts capitalized	**(343)**	**32**	11
Other income (expense), net	**(13)**	**4**	(17)
Income taxes	**625**	**172**	43
Net income	**1,162**	**195**	136
Dividends on preferred and preference stock	**17**	**—**	—
Net income after dividends on preferred and preference stock	**$1,145**	**$ 195**	$136

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Operating Revenues

Details of operating revenues were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail — prior year	**$7,608**	$6,912
Estimated change in —		
Rates and pricing	**703**	—
Sales growth (decline)	**(9)**	48
Weather	**(105)**	207
Fuel cost recovery	**(98)**	441
Retail — current year	**8,099**	7,608
Wholesale revenues —		
Non-affiliates	**341**	380
Affiliates	**32**	53
Total wholesale revenues	**373**	433
Other operating revenues	**328**	308
Total operating revenues	**$8,800**	$8,349
Percent change	**5.4%**	8.5%

Retail base revenues of $4.8 billion in 2011 increased by $588 million, or 14.0%, from 2010 primarily due to increases authorized under the 2010 ARP, which became effective January 1, 2011. This increase was partially offset by closer to normal weather in 2011 compared to 2010. The increase in base revenues also includes the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Funds Used During Construction Equity" and "Interest Expense, Net of Amounts Capitalized" herein for additional information. Residential base revenues increased $225 million, or 11.8%, commercial base revenues increased $236 million, or 14.1%, and industrial base revenues increased $118 million, or 21.4%.

Retail base revenues of $4.2 billion in 2010 increased by $255 million, or 6.5%, from 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 when compared to the corresponding periods in 2009. Residential base revenues increased $187 million, or 10.9%, commercial base revenues increased $50 million, or 3.1%, and industrial base revenues increased $17 million, or 3.1%. Revenues from changes in rates and pricing in 2010 were flat as the increased recognition of environmental compliance cost recovery (ECCR) revenues in accordance with the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan) was offset by pricing reductions from the structure of the Company's traditional base rate tariffs.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" herein for additional information.

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Wholesale revenues from sales to non-affiliated utilities were as follows:

	2011	2010	2009
		(in millions)	
Other power sales —			
Capacity and other	**$177**	$155	$140
Energy	**164**	194	186
Total	**341**	349	326
Unit power sales —			
Capacity	**—**	18	43
Energy	**—**	13	26
Total	**—**	31	69
Total non-affiliated	**$341**	$380	$395

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA) and short-term opportunity sales, and from a unit power sales agreement which has now expired. Wholesale revenues from PPAs and unit power sales agreements have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Revenues from other non-affiliated sales decreased $8 million, or 2.3%, in 2011 and increased $23 million, or 7.1%, in 2010. The decrease in 2011 was primarily due to a 16.3% decrease in kilowatt-hour (KWH) sales from lower demand resulting from closer to normal weather in 2011 compared to 2010 and the lower market costs of available energy compared to Company-owned generation. The increase in 2010 was primarily due to higher fuel costs and revenues from a PPA that replaced the unit power sales agreement that expired in May 2010.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2011 and 2010, wholesale revenues from sales to affiliates decreased $21 million and $59 million from the prior year, respectively, due to decreases of 37.4% and 60.1%, respectively, in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of Company-owned generation. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $20 million, or 6.5%, in 2011 from the prior year primarily due to new contracts that replaced the transmission component of a unit power sales agreement that expired in May 2010 and increased usage of the Company's transmission system by non-affiliate companies. Other operating revenues increased $35 million, or 12.8%, in 2010 from the prior year primarily due to a $25 million increase in transmission revenues related to increased usage of the Company's transmission system by non-affiliated companies, an increase of $4 million in outdoor lighting revenues primarily as a result of new customer sales associated with government stimulus programs, and an increase of $6 million in late payment fees and customer maintenance request revenues.

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Energy Sales

Changes in revenues are influenced heavily by the change in volume of energy sold from year to year. KWH sales for 2011 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in billions)				
Residential	**27.2**	**(7.5)%**	12.0%	**(0.4)%**	0.9%
Commercial	**32.9**	**(2.8)**	3.9	**(0.4)**	(0.4)
Industrial	**23.5**	**1.3**	6.4	**1.6**	5.1
Other	**0.7**	**(0.9)**	(1.2)	**(0.6)**	(1.9)
Total retail	**84.3**	**(3.3)**	7.1	**0.2%**	1.5%
Wholesale					
Non-affiliates	**3.9**	**(16.3)**	(10.5)		
Affiliates	**0.6**	**(37.4)**	(60.1)		
Total wholesale	**4.5**	**(20.0)**	(26.6)		
Total energy sales	**88.8**	**(4.3)%**	4.2%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

In 2011, residential and commercial KWH sales decreased compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Industrial KWH sales increased in 2011 compared to 2010 primarily due to increased demand in the primary metals sector.

In 2010, residential, commercial, and industrial KWH sales increased compared to 2009 primarily due to colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 when compared to the corresponding periods in 2009 and a slowly improving economy.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

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Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's electricity generated and purchased were as follows:

	2011	2010	2009
Total generation *(billions of KWHs)*	**65.5**	75.3	72.4
Total purchased power *(billions of KWHs)*	**26.8**	21.7	20.4
Sources of generation *(percent)* -			
Coal	**62**	67	67
Nuclear	**23**	21	21
Gas	**13**	10	10
Hydro	**2**	2	2
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**4.70**	4.53	4.12
Nuclear	**0.78**	0.66	0.55
Gas	**4.92**	5.75	5.30
Average cost of fuel, generated *(cents per net KWH)*	**3.80**	3.82	3.48
Average cost of purchased power *(cents per net KWH)* *	**5.38**	5.64	6.06

* Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $3.9 billion in 2011, a decrease of $156 million, or 3.9%, compared to 2010. This decrease was primarily due to an $86 million decrease in the average cost of purchased power and gas, partially offset by increases in the average cost of coal and nuclear fuel. The decrease was also due to a $358 million decrease related to fewer KWHs generated as a result of lower customer demand, partially offset by a $288 million increase in KWHs purchased as the market cost of energy was lower than Company-owned generation.

Fuel and purchased power expenses were $4.0 billion in 2010, an increase of $352 million, or 9.5%, compared to 2009. This increase was due to a $160 million increase in the average cost of fossil and nuclear fuel and a $192 million increase related to more KWHs generated primarily due to higher customer demand as a result of colder weather in the first and fourth quarters of 2010 and warmer weather in the second and third quarters of 2010 when compared to the corresponding periods in 2009.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011. In early 2011, uranium prices continued the steady increase started during the second half of 2010. In March 2011, uranium prices fell sharply from the highs earlier in the year. After some price volatility in the second quarter 2011, the price leveled and remained relatively constant for the remainder of 2011. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2011; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" herein for additional information.

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Other Operations and Maintenance Expenses

In 2011, other operations and maintenance expenses increased $43 million, or 2.5%, compared to 2010. The increase was due to a $22 million increase in customer assistance expenses related to new demand side management programs in 2011, an $8 million increase in uncollectible account expense as a result of higher revenues and current economic conditions, and a $6 million increase in workers compensation expense resulting from a higher volume of claims.

In 2010, other operations and maintenance expenses increased $240 million, or 16.1%, compared to 2009. The increase was primarily due to increases of $142 million in power generation, $74 million in transmission and distribution, and $25 million in customer accounting, service, and sales due to cost containment efforts in 2009 as a result of economic conditions. The increase in power generation operations and maintenance expenses was also due to higher generation levels to meet increased customer demand in 2010.

Depreciation and Amortization

Depreciation and amortization increased $157 million, or 28.1%, in 2011 compared to 2010. This increase was primarily due to a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Rate Plans" herein, Note 1 to the financial statements under "Depreciation and Amortization," and Note 3 to the financial statements under "Retail Regulatory Matters — Rate Plans" for additional information.

Depreciation and amortization decreased $97 million, or 14.8%, in 2010 compared to the prior year. This decrease was primarily due to a $133 million increase in amortization of the regulatory liability related to other cost of removal obligations, as authorized by the Georgia PSC, partially offset by increased depreciation related to additional plant in service related to transmission, distribution, and environmental projects.

Taxes Other Than Income Taxes

In 2011, taxes other than income taxes increased $25 million, or 7.3%, from the prior year primarily due to a $17 million increase in property taxes and a $9 million increase in municipal franchise fees related to retail revenues. In 2010, taxes other than income taxes increased $27 million, or 8.5%, from the prior year primarily due to municipal franchise fees resulting from retail revenues during 2010.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $51 million, or 34.7%, in 2011 compared to the prior year primarily due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized with an offsetting increase in operating revenues through the NCCR tariff. AFUDC equity increased $50 million, or 51.5%, in 2010 compared to the prior year primarily due to the increase in construction related to three new combined cycle units at Plant McDonough, Plant Vogtle Units 3 and 4, and ongoing environmental and transmission projects. See FUTURE EARNINGS POTENTIAL — "Construction" herein and Note 3 to the financial statements under "Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2011, interest expense, net of amounts capitalized decreased $32 million, or 8.5%, from the prior year primarily due to a reduction of $23 million in interest expense related to the settlement of litigation with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds, partially offset by a reduction in AFUDC debt due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base. See Note 3 to the financial statements under "Income Tax Matters" for additional information on the Georgia DOR settlement. In 2010, interest expense, net of amounts capitalized decreased $11 million, or 2.8%, from the prior year primarily due to a $14 million increase in interest capitalized compared to the prior year as a result of increased construction activity.

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Other Income (Expense), Net

The 2011 increase in other income (expense), net compared to the prior year was immaterial. Other income (expense), net decreased $17 million in 2010 compared to the prior year primarily as a result of a $9 million decrease in wholesale operating fees and increased donations of $5 million.

Income Taxes

Income taxes increased $172 million, or 38.0%, in 2011 compared to the prior year primarily due to higher pre-tax earnings, a decrease in non-taxable AFUDC equity, and the recognition in 2010 of certain state income tax credits. Income taxes increased $43 million, or 10.5%, in 2010 compared to the prior year primarily due to higher pre-tax earnings, partially offset by increases in non-taxable AFUDC equity and state income tax credits.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES — "Application of Critical Accounting Policies and Estimates — Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. The Company's ECCR tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

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New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power Company (Alabama Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the Company had invested approximately $3.8 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $101 million, $217 million, and $440 million for 2011, 2010, and 2009, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $714 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$237	$249	$228

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $237 million as described below.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $5 billion to $7 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $237 million that is also included in the 2012 through 2013 base level capital investment of the Company described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $320 million from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $640 million over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	—	Up to $70	Up to $250
Proposed water and coal combustion byproducts rules	Up to $30	Up to $160	Up to $450
Total potential incremental environmental compliance investments	**Up to $30**	**Up to $230**	**Up to $700**

The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Company's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information.

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As of December 31, 2011, the Company had total generating capacity of approximately 16,588 megawatts (MWs), of which 9,124 MWs are coal-fired. Over the past several years, the Company has installed various pollution control technologies on its coal-fired units, including both selective catalytic reduction equipment and scrubbers on its eight largest coal units making up 5,200 MWs of the Company's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Company is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including on the units with existing pollution control technologies), and changing fuel sources for certain units.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, jointly owned with Alabama Power, is also developing an environmental compliance strategy for its 1,000 MWs of coal-fired generating capacity, which may result in unit retirements, installation of controls, or changing fuel source. The capacity of SEGCO's units is sold to the Company and Alabama Power through a PPA. The impact of SEGCO's compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company spent approximately $3.5 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. The 2008 standard is expected to result in designation of new nonattainment areas within the Company's service territory and could require additional reductions in NO_x emissions.

The EPA also regulates fine particulate matter emissions on an annual and 24-hour average basis. Although all areas within the Company's service territory have air quality levels that attain the current standard, the EPA has announced its intention to propose new, more stringent annual and 24-hour fine particulate matter standards in mid-2012.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Company's service territory were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the State of Georgia.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the Company's facilities which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

On March 21, 2011, the EPA published the final Industrial Boiler (IB) Maximum Achievable Control Technology (MACT) rule establishing emissions limits for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. At the same time, the EPA issued a notice of intent to reconsider the final rule and, on May 16, 2011, the EPA issued an administrative stay to prevent the rule from becoming effective. On December 2, 2011, the EPA proposed a reconsideration rule to change certain aspects of the final rule. On January 9, 2012, however, the U.S. District Court for the District of Columbia Circuit vacated the EPA's administrative stay. Although the U.S. District Court for the District of Columbia Circuit's decision would allow the original IB MACT rule to become effective, the EPA has indicated that it will not implement the rule until the EPA's proposed revisions can be finalized. The effect of the regulatory proceedings will depend on the final form of the revised regulations and the outcome of any legal challenges and cannot be determined at this time. On October 18, 2011, the Georgia PSC approved the Company's request to further delay the decision to convert Plant Mitchell Unit 3 from coal to biomass for two to four years, until there is greater clarity regarding the IB MACT rule and other proposed and recently adopted regulations.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, the MATS rule, and the IB MACT rule on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2011, the Company had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. As a result of uncertainties related to the potential federal air quality regulations described above, the Company has suspended certain work related to the installation of emissions control equipment at Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7. The Company continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. The Company may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls. See "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information.

The ultimate outcome of these matters cannot be determined at this time.

Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs, as described previously, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The Company currently operates 11 electric generating plants with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Georgia and Alabama each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

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While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described previously, that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

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Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 58 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2011 greenhouse gas emissions on the same basis is approximately 45 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company is actively constructing new generating facilities with lower greenhouse gas emissions. These include Plant Vogtle Units 3 and 4 and two additional combined cycle units at Plant McDonough. The Company has also proposed the conversion of Plant Mitchell from coal-fired to biomass generation and is currently evaluating the costs and viability of other renewable technologies for the State of Georgia.

PSC Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In December 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff (Advocacy Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been or will be made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Construction – Other Construction" herein for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

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Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2010 ARP is in effect. The Company is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

2011 Integrated Resource Plan Update

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the 2010 ARP.

On August 4, 2011, the Company filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included the Company's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. The Company also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, the Company is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 MWs of capacity. The Company is currently updating its economic analysis of these units based on the final MATS rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, the Company cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes the Company's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process.

In addition, the Company filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, the Company entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated Integrated Resource Plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on the Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

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Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved an increase in the Company's total annual billings of approximately $373 million effective April 2010, as well as a decrease of approximately $43 million effective June 1, 2011. In addition, the Georgia PSC has authorized an interim fuel rider, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. The Company currently expects to file its next case on March 30, 2012, with rates to be effective July 1, 2012.

The Company's under recovered fuel balance totaled approximately $137 million at December 31, 2011, all of which is included in current assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2011, the balance in the regulatory asset related to storm damage was $43 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. The Company also filed similar claims for the years 2002 through 2004. In 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, the Company and the Georgia DOR agreed to a settlement resolving the claims. As a result, the Company recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, the Company recorded a reduction of approximately $23 million in related interest expense. See "Construction – Other Construction" herein and Note 3 under "Retail Regulatory Matters – Construction – Other Construction" and "Income Tax Matters – Georgia State Income Tax Credits" for additional information on this regulatory liability.

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Consequently, it is estimated there will be a positive cash flow benefit of between $325 million and $400 million in 2012.

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Nuclear

In 2009, the Nuclear Regulatory Commission (NRC) issued an Early Site Permit and Limited Work Authorization to Southern Nuclear Operating Company (Southern Nuclear), on behalf of the Company, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to Plant Vogtle Units 3 and 4. See Note 4 to the financial statements for additional information on the Owners. In 2008, Southern Nuclear filed applications with the NRC for the combined construction and operating licenses (COLs) for the new units. The NRC certified the Westinghouse Electric Company LLC's (Westinghouse) Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively.

On February 16, 2012, a group of four plaintiffs who had intervened in the NRC's COL proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the DCD. The Company intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved the Company's NCCR tariff. The NCCR tariff became effective January 1, 2011 and annual adjustments are filed with the Georgia PSC on November 1 to become effective on January 1 of the following year. The Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2011, approximately $73 million of these 2009 and 2010 costs remained in construction work in progress. At December 31, 2011, the Company's portion of construction work in progress for Plant Vogtle Units 3 and 4 was $1.9 billion.

On February 10, 2012, the Georgia PSC voted to approve the Company's fifth semi-annual construction monitoring report including total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 MWs each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

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Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COLs or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in accordance with the Vogtle 3 and 4 Agreement in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and the Company (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including potential costs associated with design changes the Consortium made to the DCD during the NRC review process and potential costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Consortium has not specified the amount of these costs, but such costs could be substantial, and the Company expects the Consortium to seek recovery of these costs. The Company is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the Vogtle 3 and 4 Agreement. The Company has not agreed that the Owners have responsibility for any of these costs and, with regard to most of these costs, denies any liability and the Company intends to vigorously defend itself in these matters. The Company expects negotiations with the Consortium to continue over the next several months. If these costs are imposed upon the Owners, the Company would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4 if necessary. Additional claims by the Consortium and the Company (on behalf of the Owners) may arise throughout the construction of Plant Vogtle Units 3 and 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

The Company is currently constructing Plant McDonough Units 5 and 6 which are expected to be placed into service in May and November 2012, respectively. The Company completed construction of Plant McDonough Unit 4 and placed it into service on December 28, 2011. On January 24, 2012, the Georgia PSC approved a stipulation agreement between the Company and the Georgia PSC Advocacy Staff to increase the certified amount for the project by 3.9% and to amortize $62 million of a regulatory liability for state income tax credits over a 21-month period beginning April 2012. See "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information on this regulatory liability and "PSC Matters – Rate Plans" herein for additional information on base rate increases in 2012 and 2013 associated with the new units.

The Georgia PSC has also approved the Company's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2011. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time.

See RISK FACTORS of the Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

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Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $9 million or less change in total benefit expense and a $122 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company funded approximately $4 million to its nuclear decommissioning trust funds in 2011 and expects to fund approximately $2 million in 2012 and 2013.

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Net cash provided from operating activities totaled $2.6 billion in 2011, an increase of $785 million from 2010, primarily due to higher retail operating revenues, increased deferred income taxes in 2011 primarily due to bonus depreciation, and contributions to the qualified pension plan in 2010. Net cash provided from operating activities totaled $1.8 billion in 2010, an increase of $429 million from 2009, primarily due to a $136 million increase in net income, fuel inventory reductions in 2010 compared to additions in 2009, and a net increase of $94 million in deferred and prepaid income taxes primarily due to the extension of bonus depreciation and the change in the tax accounting method for repair costs (See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – and "Bonus Depreciation" herein), partially offset by contributions to the qualified pension plan.

Net cash used for investing activities totaled $1.8 billion, $2.2 billion, and $2.4 billion in 2011, 2010, and 2009, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash (used for)/provided from financing activities totaled $(836) million, $391 million, and $881 million for 2011, 2010, and 2009, respectively. The decrease in 2011 compared to 2010 was primarily a reflection of lower capital contributions from Southern Company and higher common stock dividends paid to Southern Company and lower debt issuances due to the availability of more internally generated cash in 2011. The decrease in 2010 when compared to 2009 was primarily related to additional issuances of senior notes and an increase in notes payable, partially offset by an increase in the redemption of senior notes. The statements of cash flows provide additional details. See "Financing Activities" herein for additional information.

Significant balance sheet changes in 2011 include a $1.2 billion increase in property, plant, and equipment related to the construction activities discussed above, a $670 million increase in accumulated deferred income taxes primarily related to bonus depreciation, and a $231 million increase in paid in capital reflecting equity contributions from Southern Company.

The Company's ratio of common equity to total capitalization, including short-term debt, was 49.4% in 2011 and 48.8% in 2010. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to potential U.S. Department of Energy (DOE) loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

In June 2010, the Company reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by the Company related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to the Company and secured by a first priority lien on the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for the Company. See FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein and Note 3 to the financial statements under "Construction – Nuclear" for more information on Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Georgia PSC and the FERC, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

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The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs which can fluctuate significantly due to the seasonality of the business.

At December 31, 2011, the Company had approximately $13 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires [(a)]			
2014	2016	Total	Unused
	(in millions)		
$250	$1,500	$1,750	$1,745

(a) No credit arrangements expire in 2012, 2013, or 2015.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2011, the Company had $868 million outstanding variable rate pollution control revenue bonds requiring liquidity support.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings, excluding $2 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		**Short-term Debt During the Period** [(a)]		
	Amount Outstanding	**Weighted Average Interest Rate**	**Average Outstanding**	**Weighted Average Interest Rate**	**Maximum Amount Outstanding**
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$ 313	0.20%	$ 208	0.26%	$ 681
Short-term bank debt	200	1.18%	9	1.18%	200
Total	$ 513	0.51%	$ 217	0.33%	
December 31, 2010:					
Commercial paper	$ 575	0.30%	$ 167	0.25%	$ 575

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

Pollution Control Revenue Bonds

In December 2010, the Development Authority of Floyd County issued $53 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Hammond Project), First Series 2010 for the benefit of the Company. These bonds were purchased and held by the Company as of December 31, 2010. In January 2011, the Company remarketed these bonds to investors in a variable interest rate mode.

In January 2011, the Company purchased and held $83.5 million of pollution control revenue bonds. The Company remarketed these bonds to investors in January 2011. In addition, in April 2011, the Company purchased and held $113.5 million of pollution control revenue bonds. The Company remarketed these bonds to investors in June 2011.

In July 2011, the Company redeemed $67 million of the Development Authority of Appling County Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), First Series 2006. In September 2011, the Development Authority of Appling County issued $67 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), First Series 2011 due September 1, 2041 for the benefit of the Company. The bonds were issued in a variable interest rate mode.

In July 2011, approximately $8 million of Development Authority of Cobb County Pollution Control Revenue Bonds (Georgia Power Company Plant McDonough Project), First Series 1991 matured.

In September 2011, the Company remarketed $173 million aggregate principal amount of the Development Authority of Bartow County Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009 and $114.3 million aggregate principal amount of the Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2009 to investors in a variable interest rate mode. The Company had purchased and was holding the bonds as of December 31, 2010.

In September 2011, the Company redeemed approximately $14.1 million aggregate principal amount of Development Authority of Coweta County Pollution Control Revenue Bonds (Georgia Power Company Plant Yates Project), Second Series 2001.

In November 2011, the Company redeemed $53 million aggregate principal amount of the Development Authority of Burke County Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Third Series 1999.

Senior Notes and Trust Preferred Securities

In January 2011, the Company's $100 million aggregate principal amount of Series S 4.00% Senior Notes due January 15, 2011 matured.

In January 2011, the Company issued $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes due January 15, 2013. The proceeds were used to repay short-term debt and for general corporate purposes, including the Company's continuous construction program.

In April 2011, the Company issued $250 million aggregate principal amount of Series 2011B 3.00% Senior Notes due April 15, 2016. The proceeds were used to repay short-term debt and for general corporate purposes, including the Company's continuous construction program.

In September 2011, the Company redeemed (i) $140.7 million aggregate principal amount of Series M 5.40% Senior Insured Notes due March 1, 2033, (ii) $35 million aggregate principal amount of Savannah Electric Series F 5.50% Senior Notes due December 12, 2028, and (iii) $200 million aggregate principal amount of Series G 5-7/8% Junior Subordinated Notes due January 15, 2044 and the related Trust Preferred Securities of Georgia Power Capital Trust VII (as well as approximately $6.2 million of such Series G Junior Subordinated Notes related to the Company's ownership of the common securities of Georgia Power Capital Trust VII).

In December 2011, the Company redeemed $150 million aggregate principal amount of Series 2006A 5.65% Senior Insured Quarterly Notes due December 15, 2040.

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Other

In March 2011, the Company's $300 million variable rate bank term loan due on March 4, 2011 matured and was partially replaced by two one-year $125 million aggregate principal amount variable rate bank loans that bear interest based on one-month London Interbank Offered Rate (LIBOR).

In December 2011, the Company entered into three six-month floating rate bank loans bearing interest based on one-month LIBOR. These short-term loans were for $75 million, $75 million, and $50 million aggregate principal amounts, and proceeds were used to repay short-term debt and for general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2011, the Company entered into a floating rate six-month short-term bank loan in an aggregate amount of $100 million, bearing interest based on one-month LIBOR. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2011 were as follows:

Credit Ratings	**Maximum Potential Collateral Requirements**
	(in millions)
At BBB- and/or Baa3	$ 68
Below BBB- and/or Baa3	1,534

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $2.0 billion of outstanding variable rate long-term debt and short-term bank loans, at January 1, 2012 was 0.56%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $20 million at January 1, 2012. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

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To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The Company continues to manage a fuel hedging program implemented per the guidelines of the Georgia PSC.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(100)**	$ (75)
Contracts realized or settled	**92**	85
Current period changes [(a)]	**(74)**	(110)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (82)**	$(100)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was an increase of $18 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, the Company had a net hedge volume of 73.3 million mmBtu with a weighted average swap contract cost approximately $1.65 per mmBtu above market prices, and at December 31, 2010 had a net hedge volume of 58.7 million mmBtu with a weighted average swap contract cost approximately $1.74 per mmBtu above market prices. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2011 and 2010, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program, which has a 48-month time horizon. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011		
	Total Fair Value	Maturity Year 1	Maturity Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(82)	(60)	(22)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(82)	$(60)	$(22)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

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Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as detailed below. Although its analyses are preliminary, the Company estimates that the aggregate capital costs to the Company for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $5 billion to $7 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rules. Included in this amount is $237 million that is also included in the 2012 through 2013 base level capital investment of the Company, described herein in anticipation of these rules. The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$2,066	$ 2,121	$ 1,887
Existing environmental statutes and regulations	237	249	228
Total construction program base level capital investment	**$2,303**	**$ 2,370**	**$ 2,115**
Potential incremental environmental compliance investments:			
MATS rule	—	Up to $70	Up to $250
Proposed water and coal combustion byproducts rules	Up to $30	Up to $160	Up to $450
Total potential incremental environmental compliance investments	**Up to $30**	**Up to $230**	**Up to $700**

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 and Note 7 to the financial statements under "Construction — Nuclear" and "Construction Program," respectively, for additional information.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing (d)	Total
				(in millions)		
Long-term debt (a) —						
Principal	$ 450	$ 1,675	$ 504	$ 5,805	$—	$ 8,434
Interest	340	613	555	4,640	—	6,148
Preferred and preference stock dividends (b)	17	35	35	—	—	87
Energy-related derivative obligations (c)	68	27	—	—	—	95
Operating leases	34	52	25	8	—	119
Capital leases	5	10	12	28	—	55
Unrecognized tax benefits and interest (d)	17	—	—	—	36	53
Purchase commitments (e) —						
Capital (f)	2,054	4,030	—	—	—	6,084
Limestone (g)	18	36	13	8	—	75
Coal	1,473	1,615	461	238	—	3,787
Nuclear fuel	257	330	173	528	—	1,288
Natural gas (h)	546	1,148	826	2,179	—	4,699
Purchased power (i)	262	484	488	1,846	—	3,080
Long-term service agreements (j)	22	102	109	472	—	705
Trusts —						
Nuclear decommissioning (k)	2	3	3	34	—	42
Pension and other postretirement benefit plans (l)	37	68	—	—	—	105
Total	$5,602	$10,228	$3,204	$15,786	$36	$34,856

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2012, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred and preference stock do not mature; therefore, amounts provided are for the next five years only.

(c) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $36 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 under "Unrecognized Tax Benefits" to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2011, 2010, and 2009 were $1.8 billion, $1.7 billion, and $1.5 billion, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $30 million, up to $230 million, and up to $700 million for 2012, 2013, and 2014, respectively. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce SO_2 emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(i) Excludes four PPAs that are subject to certification by the Georgia PSC. See Note 3 under "Retail Regulatory Matters – 2011 Integrated Resource Plan Update" to the financial statements for additional information.

(j) Long-term service agreements include price escalation based on inflation indices.

(k) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP.

(l) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2011 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, the Company's projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, start and completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, the pending EPA civil action against the Company, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;

- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements

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STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Georgia Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Revenues:			
Retail revenues	**$8,099**	$7,608	$6,912
Wholesale revenues, non-affiliates	**341**	380	395
Wholesale revenues, affiliates	**32**	53	112
Other revenues	**328**	308	273
Total operating revenues	**8,800**	8,349	7,692
Operating Expenses:			
Fuel	**2,789**	3,102	2,717
Purchased power, non-affiliates	**390**	368	269
Purchased power, affiliates	**713**	578	710
Other operations and maintenance	**1,777**	1,734	1,494
Depreciation and amortization	**715**	558	655
Taxes other than income taxes	**369**	344	317
Total operating expenses	**6,753**	6,684	6,162
Operating Income	**2,047**	1,665	1,530
Other Income and (Expense):			
Allowance for equity funds used during construction	**96**	147	97
Interest expense, net of amounts capitalized	**(343)**	(375)	(386)
Other income (expense), net	**(13)**	(17)	—
Total other income and (expense)	**(260)**	(245)	(289)
Earnings Before Income Taxes	**1,787**	1,420	1,241
Income taxes	**625**	453	410
Net Income	**1,162**	967	831
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$1,145**	$ 950	$ 814

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Georgia Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$1,145**	$950	$814
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(1), respectively	**—**	—	(2)
Reclassification adjustment for amounts included in net income, net of tax of $2, $6, and $9, respectively	**2**	10	14
Total other comprehensive income (loss)	**2**	10	12
Comprehensive Income	**$1,147**	$960	$826

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
Georgia Power Company 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Activities:			
Net income	**$ 1,162**	$ 967	$ 831
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**867**	724	791
Deferred income taxes	**500**	342	191
Deferred revenues	**(1)**	(101)	(49)
Allowance for equity funds used during construction	**(96)**	(147)	(97)
Pension and postretirement funding	**(15)**	(195)	(22)
Other, net	**(36)**	29	23
Changes in certain current assets and liabilities —			
-Receivables	**235**	168	127
-Fossil fuel stock	**(99)**	103	(242)
-Prepaid income taxes	**72**	(36)	21
-Other current assets	**(21)**	(9)	(7)
-Accounts payable	**44**	(99)	(54)
-Accrued taxes	**(36)**	31	(19)
-Accrued compensation	**7**	62	(101)
-Other current liabilities	**49**	8	25
Net cash provided from operating activities	**2,632**	1,847	1,418
Investing Activities:			
Property additions	**(1,861)**	(2,190)	(2,515)
Nuclear decommissioning trust fund purchases	**(1,845)**	(1,772)	(989)
Nuclear decommissioning trust fund sales	**1,841**	1,768	984
Cost of removal, net of salvage	**(42)**	(67)	(56)
Change in construction payables, net of joint owner portion	**123**	36	106
Other investing activities	**(7)**	(19)	52
Net cash used for investing activities	**(1,791)**	(2,244)	(2,418)
Financing Activities:			
Increase (decrease) in notes payable, net	**(61)**	252	(33)
Proceeds —			
Capital contributions from parent company	**214**	688	931
Pollution control revenue bonds issuances and remarketings	**604**	—	417
Senior notes issuances	**550**	1,950	1,000
Other long-term debt issuances	**250**	—	1
Redemptions and repurchases —			
Pollution control revenue bonds	**(339)**	(516)	(327)
Senior notes	**(427)**	(1,112)	(333)
Other long-term debt	**(303)**	—	—
Long-term debt to affiliate trust	**(206)**	—	—
Payment of preferred and preference stock dividends	**(17)**	(18)	(18)
Payment of common stock dividends	**(1,096)**	(820)	(739)
Other financing activities	**(5)**	(33)	(18)
Net cash provided from (used for) financing activities	**(836)**	391	881
Net Change in Cash and Cash Equivalents	**5**	(6)	(119)
Cash and Cash Equivalents at Beginning of Year	**8**	14	133
Cash and Cash Equivalents at End of Year	**$ 13**	$ 8	$ 14
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $37, $54 and $40 capitalized, respectively)	**$ 346**	$ 339	$ 341
Income taxes (net of refunds)	**54**	149	228
Noncash transactions - accrued property additions at year-end	**391**	310	243

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
At December 31, 2011 and 2010
Georgia Power Company 2011 Annual Report

Assets	2011	2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 13**	$ 8
Receivables —		
Customer accounts receivable	**571**	580
Unbilled revenues	**172**	172
Under recovered regulatory clause revenues	**137**	184
Joint owner accounts receivable	**87**	60
Other accounts and notes receivable	**61**	67
Affiliated companies	**26**	21
Accumulated provision for uncollectible accounts	**(13)**	(11)
Fossil fuel stock, at average cost	**723**	624
Materials and supplies, at average cost	**406**	371
Vacation pay	**82**	78
Prepaid income taxes	**71**	99
Other regulatory assets, current	**108**	105
Other current assets	**106**	80
Total current assets	**2,550**	2,438
Property, Plant, and Equipment:		
In service	**27,804**	26,397
Less accumulated provision for depreciation	**10,296**	9,966
Plant in service, net of depreciation	**17,508**	16,431
Other utility plant, net	**55**	—
Nuclear fuel, at amortized cost	**443**	386
Construction work in progress	**3,274**	3,287
Total property, plant, and equipment	**21,280**	20,104
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**63**	70
Nuclear decommissioning trusts, at fair value	**667**	818
Miscellaneous property and investments	**44**	42
Total other property and investments	**774**	930
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**756**	723
Prepaid pension costs	**—**	91
Deferred under recovered regulatory clause revenues	**—**	214
Other regulatory assets, deferred	**1,604**	1,207
Other deferred charges and assets	**187**	207
Total deferred charges and other assets	**2,547**	2,442
Total Assets	**$27,151**	$25,914

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
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Georgia Power Company 2011 Annual Report

Liabilities and Stockholder's Equity	2011	2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 455**	$ 415
Notes payable	**515**	576
Accounts payable —		
Affiliated	**337**	243
Other	**686**	574
Customer deposits	**213**	198
Accrued taxes —		
Accrued income taxes	**36**	1
Unrecognized tax benefits	**14**	187
Other accrued taxes	**304**	328
Accrued interest	**92**	94
Accrued vacation pay	**60**	58
Accrued compensation	**125**	109
Liabilities from risk management activities	**68**	77
Other regulatory liabilities, current	**65**	31
Nuclear decommissioning trust securities lending collateral	**32**	144
Other current liabilities	**139**	134
Total current liabilities	**3,141**	3,169
Long-Term Debt (See accompanying statements)	**8,018**	7,931
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,388**	3,718
Deferred credits related to income taxes	**122**	129
Accumulated deferred investment tax credits	**220**	229
Employee benefit obligations	**905**	684
Asset retirement obligations	**734**	705
Other cost of removal obligations	**110**	131
Other deferred credits and liabilities	**224**	211
Total deferred credits and other liabilities	**6,703**	5,807
Total Liabilities	**17,862**	16,907
Preferred Stock (See accompanying statements)	**45**	45
Preference Stock (See accompanying statements)	**221**	221
Common Stockholder's Equity (See accompanying statements)	**9,023**	8,741
Total Liabilities and Stockholder's Equity	**$27,151**	$25,914
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CAPITALIZATION
At December 31, 2011 and 2010
Georgia Power Company 2011 Annual Report

	2011	2010	**2011**	2010
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
5.88% due 2044	**$ —**	$ 206		
Long-term notes payable —				
Variable rate (0.78% at 1/1/11) due 2011	**—**	300		
Variable rate (0.85% to 0.95% at 1/1/12) due 2012	**250**	—		
Variable rate (0.85% to 0.90% at 1/1/12) due 2013	**650**	350		
4.00% to 5.57% due 2011	**—**	103		
5.125% due 2012	**200**	200		
1.30% to 6.00% due 2013	**1,025**	1,025		
5.25% due 2015	**250**	250		
3.00% due 2016	**250**	—		
4.25% to 8.20% due 2017-2048	**4,025**	4,351		
Total long-term notes payable	**6,650**	6,579		
Other long-term debt —				
Pollution control revenue bonds:				
4.40% due 2016	**—**	67		
0.80% to 5.75% due 2018-2048	**916**	1,067		
Variable rate (0.39% at 1/1/11) due 2011	**—**	8		
Variable rate (0.16% at 1/1/12) due 2016	**4**	4		
Variable rate (0.10% to 0.18% at 1/1/12) due 2018-2049	**864**	373		
Total other long-term debt	**1,784**	1,519		
Capitalized lease obligations	**55**	59		
Unamortized debt discount	**(16)**	(17)		
Total long-term debt (annual interest requirement — $340 million)	**8,473**	8,346		
Less amount due within one year	**455**	415		
Long-term debt excluding amount due within one year	**8,018**	7,931	**46.4%**	46.8%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized - 50,000,000 shares				
Outstanding - 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized - 15,000,000 shares				
Outstanding - 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.5**	1.6
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398**	398		
Paid-in capital	**5,522**	5,291		
Retained earnings	**3,112**	3,063		
Accumulated other comprehensive income (loss)	**(9)**	(11)		
Total common stockholder's equity	**9,023**	8,741	**52.1**	51.6
Total Capitalization	**$17,307**	$16,938	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010, and 2009
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2008	9	$398	$3,656	$ 2,858	$(33)	$ 6,879
Net income after dividends on preferred and preference stock	—	—	—	814	—	814
Capital contributions from parent company	—	—	937	—	—	937
Other comprehensive income (loss)	—	—	—	—	12	12
Cash dividends on common stock	—	—	—	(739)	—	(739)
Balance at December 31, 2009	9	398	4,593	2,933	(21)	7,903
Net income after dividends on preferred and preference stock	—	—	—	950	—	950
Capital contributions from parent company	—	—	698	—	—	698
Other comprehensive income (loss)	—	—	—	—	10	10
Cash dividends on common stock	—	—	—	(820)	—	(820)
Balance at December 31, 2010	**9**	**398**	**5,291**	**3,063**	**(11)**	**8,741**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,145**	**—**	**1,145**
Capital contributions from parent company	**—**	**—**	**231**	**—**	**—**	**231**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**2**	**2**
Cash dividends on common stock	**—**	**—**	**—**	**(1,096)**	**—**	**(1,096)**
Balance at December 31, 2011	**9**	**$398**	**$5,522**	**$ 3,112**	**$ (9)**	**$ 9,023**

The accompanying notes are an integral part of these financial statements.

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NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2011 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $550 million in 2011, $552 million in 2010, and $506 million in 2009. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $537 million in 2011, $473 million in 2010, and $398 million in 2009.

The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $171 million, $199 million, and $411 million in 2011, 2010, and 2009, respectively. Additionally, the Company had $16 million and $26 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2011 and 2010, respectively. See Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $7 million in 2011, $9 million in 2010, and $4 million in 2009. See Note 4 for additional information.

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The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any significant services to or from affiliates in 2011, 2010, or 2009.

Also see Note 4 for information regarding the Company's ownership in and a PPA with Southern Electric Generating Company (SEGCO).

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

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NOTES (continued)
Georgia Power Company 2011 Annual Report

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2011	2010	Note
	(in millions)		
Retiree benefit plans	**$1,197**	$ 883	(a, i)
Deferred income tax charges	**713**	676	(b)
Deferred income tax charges — Medicare subsidy	**47**	51	(a)
Loss on reacquired debt	**178**	176	(c)
Asset retirement obligations	**108**	69	(b, i)
Fuel-hedging (realized and unrealized) losses	**104**	108	(d)
Vacation pay	**82**	78	(e, i)
Building leases	**43**	45	(f)
Other regulatory assets	**120**	71	(g)
Other cost of removal obligations	**(141)**	(162)	(b)
Deferred income tax credits	**(122)**	(129)	(b)
State income tax credits	**(62)**	—	(h)
Other regulatory liabilities	**(13)**	(1)	(d)
Total assets (liabilities), net	**$2,254**	$1,865	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 under "Pension Plans" and "Other Postretirement Benefits" and Note 5 under "Current and Deferred Income Taxes" for additional information.

(b) Asset retirement and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2011 other cost of removal obligations included $62 million that is being amortized over a two-year period ending December 31, 2013 in accordance with a Georgia PSC order. See Note 3 under "Retail Regulatory Matters — Rate Plans" for additional information.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(d) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the Company's fuel cost recovery mechanism.

(e) Recorded as earned by employees and recovered as paid, generally within one year.

(f) See Note 6 under "Capital Leases." Recovered over the remaining lives of the buildings through 2026.

(g) Recorded and recovered or amortized as approved by the Georgia PSC over periods not exceeding five years.

(h) Additional tax benefits resulting from the Georgia state income tax credit settlement that will be amortized over a 21-month period beginning April 2012, in accordance with a Georgia PSC order. See Note 3 under "Retail Regulatory Matters – Construction – Other Construction" and "Income Tax Matters – Georgia State Income Tax Credits" for additional information.

(i) Not earning a return as offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rate base.

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Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under “Nuclear Fuel Disposal Costs” for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are “more likely than not” of being sustained upon examination by the appropriate taxing authorities. See Note 5 under “Unrecognized Tax Benefits” for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the cost of funds used during construction.

The Company’s property, plant, and equipment in service consisted of the following at December 31:

	2011	2010
	(in millions)	
Generation	**$13,675**	$12,852
Transmission	**4,355**	4,187
Distribution	**8,125**	7,855
General	**1,621**	1,475
Plant acquisition adjustment	**28**	28
Total plant in service	**$27,804**	$26,397

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit’s operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch, respectively. Also, in accordance with a Georgia PSC order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

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Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.8% in 2011 and 3.0% in 2010 and 2009. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. See Note 3 under “Retail Regulatory Matters — Rate Plans” for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset’s future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset’s useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 3 under “Retail Regulatory Matters — Rate Plans” for additional information related to the Company’s cost of removal regulatory liability.

The asset retirement obligation liability primarily relates to the Company’s nuclear facilities, which include the Company’s ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company’s rail lines. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See “Nuclear Decommissioning” herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2011	2010
	(in millions)	
Balance at beginning of year	**$ 712**	$ 681
Liabilities incurred	**—**	—
Liabilities settled	**(9)**	(12)
Accretion	**45**	43
Cash flow revisions	**9**	—
Balance at end of year	**$ 757**	$ 712

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Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. In addition, the NRC prohibits investments in securities of power reactor licensees. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to investment brokers for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2011 and 2010, approximately $39 million and $141 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $42 million and $144 million at December 31, 2011 and 2010, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2011, investment securities in the Funds totaled $666 million, consisting of equity securities of $244 million, debt securities of $397 million, and $25 million of other securities. At December 31, 2010, investment securities in the Funds totaled $818 million, consisting of equity securities of $258 million, debt securities of $493 million, and $67 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.8 billion, $1.8 billion, and $984 million in 2011, 2010, and 2009, respectively, all of which were reinvested. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $23 million, of which $9 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $74 million, of which $25 million related to unrealized losses related to securities held in the Funds at December 31, 2010. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $119 million, of which $118 million is related to securities held in the Funds at December 31, 2009. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

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Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2009. The site study costs and accumulated provisions for decommissioning as of December 31, 2011 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2063	2067
	(in millions)	
Site study costs:		
Radiated structures	$ 583	$ 500
Non-radiated structures	46	71
Total site study costs	$ 629	$ 571
Accumulated provision	$ 399	$ 235

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2009. The current NRC estimates are $584 million and $426 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. The Georgia PSC approved annual decommissioning costs for ratemaking of $3 million annually for Plant Vogtle Units 1 and 2 for 2009 and 2010 and $2 million annually for Plant Hatch for 2011 through 2013. Based on estimates approved in the 2010 ARP, the Company projects the Funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction **(** AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2011, 2010, and 2009, the average AFUDC rates were 7.5%, 8.0%, and 8.0%, respectively, and AFUDC capitalized was $134 million, $201 million, and $137 million, respectively. AFUDC, net of income taxes, was 10.4%, 19.0%, and 14.9% of net income after dividends on preferred and preference stock for 2011, 2010, and 2009, respectively. See Note 3 under "Construction – Nuclear" for additional information on the inclusion of construction costs related to the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

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Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Under the 2010 ARP effective January 1, 2011, the Company recovers $18 million annually. In 2009 and 2010, the Company recovered $21 million annually as mandated by the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan). At December 31, 2011, the Company's regulatory asset related to storm damage was $43 million. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. Under the 2010 ARP, effective January 1, 2011, the Company recovers approximately $3 million annually through the environmental compliance cost recovery (ECCR) tariff. In 2009 and 2010, the Company recovered $1 million annually in accordance with the 2007 Retail Rate Plan. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's financial statements. As of December 31, 2011, the balance of the environmental remediation liability was $17 million, with approximately $3 million included in other regulatory assets, current and approximately $6 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2011.

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The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income after dividends on preferred and preference stock, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a VIE must consolidate the related assets and liabilities. The Company had established wholly-owned trusts to issue preferred securities. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the related investments are reflected as other investments, and the related loans from the trusts are reflected as long-term debt in the balance sheet. In September 2011, the Company redeemed all of the remaining outstanding preferred securities and related trust junior subordinated notes and subsequently dissolved the last trust.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2012, other postretirement trust contributions are expected to total approximately $23 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.52%	5.93%
Other postretirement benefit plans	**4.87**	5.40	5.83
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.25**	7.24	7.35

*Net of estimated investment management expenses of 30 basis points.

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2011 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$61	$(51)
Service and interest costs	3	(3)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.7 billion at December 31, 2011 and $2.5 billion at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,674**	$ 2,517
Service cost	**57**	54
Interest cost	**144**	145
Benefits paid	**(132)**	(127)
Actuarial loss (gain)	**166**	85
Balance at end of year	**2,909**	2,674
Change in plan assets		
Fair value of plan assets at beginning of year	**2,621**	2,237
Actual return (loss) on plan assets	**76**	335
Employer contributions	**10**	176
Benefits paid	**(132)**	(127)
Fair value of plan assets at end of year	**2,575**	2,621
Accrued liability	**$ (334)**	$ (53)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $2.8 billion and $148 million, respectively. All pension plan assets are related to the qualified pension plan.

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Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in millions)	
Prepaid pension costs	**$ —**	$ 91
Other regulatory assets, deferred	**995**	689
Current liabilities, other	**(10)**	(9)
Employee benefit obligations	**(324)**	(135)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2012.

	2011	2010	Estimated Amortization in 2012
		(in millions)	
Prior service cost	**$ 48**	$ 61	**$12**
Net (gain) loss	**947**	628	**33**
Other regulatory assets, deferred	**$995**	$689	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2009	$734
Net (gain) loss	(30)
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(13)
Amortization of net gain (loss)	(2)
Total reclassification adjustments	(15)
Total change	(45)
Balance at December 31, 2010	$689
Net (gain) loss	**324**
Change in prior service costs	**—**
Reclassification adjustments:	
Amortization of prior service costs	**(12)**
Amortization of net gain (loss)	**(6)**
Total reclassification adjustments	**(18)**
Total change	**306**
Balance at December 31, 2011	**$995**

Components of net periodic pension cost (income) were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 57**	$ 54	$ 48
Interest cost	**144**	145	147
Expected return on plan assets	**(234)**	(220)	(216)
Recognized net loss	**6**	2	2
Net amortization	**12**	13	14
Net periodic pension cost (income)	**$ (15)**	$ (6)	$ (5)

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Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2012	$144
2013	149
2014	154
2015	159
2016	165
2017 to 2021	909

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 786**	$ 782
Service cost	**7**	9
Interest cost	**41**	44
Benefits paid	**(48)**	(44)
Actuarial (gain)/loss	**(4)**	(7)
Plan amendments	**(12)**	—
Retiree drug subsidy	**4**	2
Balance at end of year	**774**	786
Change in plan assets		
Fair value of plan assets at beginning of year	**393**	369
Actual return (loss) on plan assets	**(4)**	37
Employer contributions	**20**	29
Benefits paid	**(44)**	(42)
Fair value of plan assets at end of year	**365**	393
Accrued liability	**$ (409)**	$ (393)

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in millions)	
Regulatory assets	**$ 186**	$ 179
Employee benefit obligations	**(409)**	(393)

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Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in millions)	
Prior service cost	**$ (4)**	$ 10	**$—**
Net (gain) loss	**179**	152	**4**
Transition obligation	**11**	17	**6**
Regulatory assets	**$186**	$179	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2009	$202
Net (gain) loss	(13)
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(6)
Amortization of prior service costs	(1)
Amortization of net gain (loss)	(3)
Total reclassification adjustments	(10)
Total change	(23)
Balance at December 31, 2010	$179
Net (gain) loss	**29**
Change in prior service costs/transition obligation	**(12)**
Reclassification adjustments:	
Amortization of transition obligation	**(6)**
Amortization of prior service costs	**(1)**
Amortization of net gain (loss)	**(3)**
Total reclassification adjustments	**(10)**
Total change	**7**
Balance at December 31, 2011	**$186**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 7**	$ 9	$ 10
Interest cost	**41**	44	50
Expected return on plan assets	**(30)**	(30)	(30)
Net amortization	**11**	10	13
Net postretirement cost	**$ 29**	$ 33	$ 43

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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2012	$ 49	$ (4)	$ 45
2013	51	(5)	46
2014	54	(5)	49
2015	56	(6)	50
2016	58	(7)	51
2017 to 2021	298	(38)	260

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company’s investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company’s pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**—**	—
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**39%**	41%
International equity	21	**22**	24
Domestic fixed income	25	**26**	30
Global fixed income	7	**8**	—
Special situations	1	**—**	—
Real estate investments	3	**3**	3
Private equity	2	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company’s qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private-market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

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The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are included in real estate investments and private equities in the tables below.

As of December 31, 2011:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 437	$ 202	$ —	$ 639
International equity*	449	129	—	578
Fixed income:				
U.S. Treasury, government, and agency bonds	—	164	—	164
Mortgage- and asset-backed securities	—	51	—	51
Corporate bonds	—	316	1	317
Pooled funds	—	144	—	144
Cash equivalents and other	—	53	—	53
Real estate investments	83	—	296	379
Private equity	—	—	220	220
Total	$ 969	$ 1,059	$ 517	$2,545

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 486	$ 196	$ —	$ 682
International equity*	490	170	—	660
Fixed income:				
U.S. Treasury, government, and agency bonds	—	117	—	117
Mortgage- and asset-backed securities	—	95	—	95
Corporate bonds	—	226	1	227
Pooled funds	—	77	—	77
Cash equivalents and other	1	183	—	184
Real estate investments	71	—	258	329
Private equity	—	—	245	245
Total	$ 1,048	$ 1,064	$ 504	$2,616

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	**$258**	**$245**	$217	$221
Actual return on investments:				
Related to investments held at year end	**24**	**(5)**	15	18
Related to investments sold during the year	**8**	**14**	7	7
Total return on investments	**32**	**9**	22	25
Purchases, sales, and settlements	**6**	**(34)**	19	(1)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$296**	**$220**	$258	$245

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
	(in millions)			
Assets:				
Domestic equity*	$ 85	$ 24	$—	$109
International equity*	15	31	—	46
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5	—	5
Mortgage- and asset-backed securities	—	1	—	1
Corporate bonds	—	10	—	10
Pooled funds	—	38	—	38
Cash equivalents and other	—	26	—	26
Trust-owned life insurance	—	131	—	131
Real estate investments	3	—	9	12
Private equity	—	—	7	7
Total	$103	$266	$16	$385

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2010:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 98	$ 33	$ —	$ 131
International equity*	16	39	—	55
Fixed income:				
U.S. Treasury, government, and agency bonds	—	4	—	4
Mortgage- and asset-backed securities	—	3	—	3
Corporate bonds	—	7	—	7
Pooled funds	—	28	—	28
Cash equivalents and other	—	11	—	11
Trust-owned life insurance	—	132	—	132
Real estate investments	2	—	8	10
Private equity	—	—	8	8
Total	$ 116	$ 257	$ 16	$ 389

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$ 8**	**$ 8**	$ 8	$ 8
Actual return on investments:				
Related to investments held at year end	**1**	**—**	—	—
Related to investments sold during the year	**—**	**—**	—	—
Total return on investments	**1**	**—**	—	—
Purchases, sales, and settlements	**—**	**(1)**	—	—
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$ 9**	**$ 7**	$ 8	$ 8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee’s base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $24 million, $23 million, and $25 million, respectively.

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3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million.

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In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated; however, they are not expected to have a material impact on the Company's financial statements.

In 2008, the EPA advised the Company that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA.

On September 29, 2011, the EPA issued a unilateral administrative order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the Ward Transformer Superfund site. The Company does not believe it is a liable party under CERCLA based on its alleged connection to the site. As a result, on November 7, 2011, the Company filed a response with the EPA indicating that the Company is not willing to undertake the work set forth in the UAO because the Company has sufficient cause to believe it is not a liable party. On November 22, 2011, the EPA sent the Company a letter stating that the EPA does not consider the Company to be in compliance with the UAO. The EPA also stated that it is considering enforcement options against the Company and other UAO recipients who are not complying with the UAO.

The EPA may seek to enforce the UAO in court pursuant to its enforcement authority under CERCLA and may seek recovery of its costs in undertaking the UAO work. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at the Ward Transformer Superfund site, in 2009, the Company, along with many other parties, was sued by several existing PRPs for cost recovery for a removal action that is currently taking place. The Company and numerous other defendants moved for a dismissal of these lawsuits. The court denied the dismissal of the lawsuits in March 2010 but granted the Company's motion regarding the dismissal of the claim pertaining to the plaintiffs' joint and several liability.

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The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory treatment, described in Note 1 under "Environmental Remediation Recovery," it is not expected to have a material impact on the Company's financial statements.

Income Tax Matters

Georgia State Income Tax Credits

The Company's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. The Company also filed similar claims for the years 2002 through 2004. In 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, the Company and the Georgia Department of Revenue (DOR) agreed to a settlement resolving the claims. As a result, the Company recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, the Company recorded a reduction of approximately $23 million in related interest expense. See Note 3 under "Construction – Other Construction" herein for additional information on the regulatory liability.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S., acting through the U.S. Department of Energy (DOE), that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract.

In 2007, the U.S. Court of Federal Claims awarded the Company approximately $30 million, based on its ownership interests, representing substantially all of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004.

In 2008, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to Alabama Power, but remanded the Company's portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit. The Company filed a motion for summary judgment related to a portion of the costs, which remains pending.

In 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim) due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2011 for either claim.

The final outcome of these matters cannot be determined at this time, but no material impact on the Company's net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry spent fuel storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

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Retail Regulatory Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In December 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff (Advocacy Staff), and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been or will be made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Construction – Other Construction" herein for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, the Company's retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25 % will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011. If at any time during the term of the 2010 ARP, the Company projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust the Company's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2010 ARP is in effect. The Company is required to file a general rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

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2011 Integrated Resource Plan Update

On August 4, 2011, the Company filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included the Company's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. The Company also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, the Company is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 megawatts (MWs) of capacity. The Company is currently updating its economic analysis of these units based on the final Mercury and Air Toxics Standards (MATS) rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, the Company cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes the Company's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process. If approved, these PPAs are expected to result in contractual obligations of approximately $84 million in 2015, $102 million in 2016, and $1.4 billion thereafter.

In addition, the Company filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, the Company entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated Integrated Resource Plan will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on the Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved an increase in the Company's total annual billings of approximately $373 million effective April 2010, as well as a decrease of approximately $43 million effective June 1, 2011. In addition, the Georgia PSC has authorized an interim fuel rider, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. The Company currently expects to file its next case on March 30, 2012, with rates to be effective July 1, 2012.

The Company's under recovered fuel balance totaled approximately $137 million at December 31, 2011, all of which is included in current assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

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Construction

Nuclear

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton) an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to Plant Vogtle Units 3 and 4. See Note 4 for additional information on the Owners. In 2008, Southern Nuclear filed applications with the NRC for the combined construction and operating licenses (COLs) for the new units. The NRC certified the Westinghouse Electric Company LLC's (Westinghouse) Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively.

On February 16, 2012, a group of four plaintiffs who had intervened in the NRC's COL proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the DCD. The Company intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows the Company to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered the Company to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved the Company's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and annual adjustments are filed with the Georgia PSC on November 1 to become effective on January 1 of the following year. The Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2011, approximately $73 million of these 2009 and 2010 costs remained in construction work in progress. At December 31, 2011, the Company's portion of construction work in progress for Plant Vogtle Units 3 and 4 was $1.9 billion.

On February 10, 2012, the Georgia PSC voted to approve the Company's fifth semi-annual construction monitoring report including total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. The Company will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 MWs each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

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Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COLs or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in accordance with the Vogtle 3 and 4 Agreement in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and the Company (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including potential costs associated with design changes the Consortium made to the DCD during the NRC review process and potential costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Consortium has not specified the amount of these costs, but such costs could be substantial, and the Company expects the Consortium to seek recovery of these costs. The Company is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the Vogtle 3 and 4 Agreement. The Company has not agreed that the Owners have responsibility for any of these costs and, with regard to most of these costs, denies any liability and the Company intends to vigorously defend itself in these matters. The Company expects negotiations with the Consortium to continue over the next several months. If these costs are imposed upon the Owners, the Company would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4 if necessary. Additional claims by the Consortium and the Company (on behalf of the Owners) may arise throughout the construction of Plant Vogtle Units 3 and 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC's issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

The Company is currently constructing Plant McDonough Units 5 and 6 which are expected to be placed into service in May and November 2012, respectively. The Company completed construction of Plant McDonough Unit 4 and placed it into service on December 28, 2011. On January 24, 2012, the Georgia PSC approved a stipulation agreement between the Company and the Georgia PSC Advocacy Staff to increase the certified amount for the project by 3.9% and to amortize $62 million of a regulatory liability for state income tax credits over a 21-month period beginning April 2012. See "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information on this regulatory liability and "PSC Matters – Rate Plans" herein for additional information on base rate increases in 2012 and 2013 associated with the new units.

The Georgia PSC has also approved the Company's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2011. The Company will continue to file quarterly construction monitoring reports throughout the construction period.

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4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $141 million in 2011, $100 million in 2010, and $87 million in 2009 and is included in purchased power from affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Florida Power Corporation (Progress Energy Florida) jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida.

At December 31, 2011, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)			
Units 1 and 2	45.7%	$3,296	$1,962
Plant Hatch (nuclear)	50.1	978	545
Plant Wansley (coal)	53.5	709	225
Plant Scherer (coal)			
Units 1 and 2	8.4	157	76
Unit 3	75.0	1,108	373
Rocky Mountain (pumped storage)	25.4	175	113
Intercession City (combustion-turbine)	33.3	12	4

At December 31, 2011, the Company's portion of construction work in progress related to environmental projects at Plants Wansley and Scherer was $36 million and $63 million, respectively. The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in millions)	
Federal –			
Current	**$106**	$147	$211
Deferred	**479**	312	175
	585	459	386
State –			
Current	**19**	(36)	7
Deferred	**21**	30	17
	40	(6)	24
Total	**$625**	$453	$410

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$3,687**	$3,184
Property basis differences	**804**	746
Employee benefit obligations	**257**	251
Fuel clause under recovery	**56**	162
Premium on reacquired debt	**72**	71
Regulatory assets associated with employee benefit obligations	**481**	336
Asset retirement obligations	**299**	275
Other	**103**	70
Total	**5,759**	5,095
Deferred tax assets –		
Federal effect of state deferred taxes	**157**	159
Employee benefit obligations	**585**	433
Other property basis differences	**106**	111
Other deferred costs	**55**	72
Cost of removal obligations	**40**	52
State tax credit carry forward	**52**	192
Unbilled fuel revenue	**45**	57
Asset retirement obligations	**299**	275
Other	**63**	44
Total	**1,402**	1,395
Total deferred tax liabilities, net	**4,357**	3,700
Portion included in current assets/(liabilities), net	**31**	18
Accumulated deferred income taxes	**$4,388**	$3,718

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At December 31, 2011, tax-related regulatory assets were $760 million. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. In 2010, the Company deferred $51 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The Company began amortizing the regulatory asset in 2011 to income tax expense over 12 years under the 2010 ARP.

At December 31, 2011, tax-related regulatory liabilities to be credited to customers were $184 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. In 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia DOR resolving claims for tax credits in its 2005 through 2009 income tax filings. See Note 3 under "Income Tax Matters" for additional information.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $9 million in 2011, $13 million in 2010, and $14 million in 2009. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had been utilized.

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.5**	(0.3)	1.2
Non-deductible book depreciation	**0.8**	1.0	1.1
AFUDC equity	**(1.9)**	(3.6)	(2.7)
Donations	**—**	—	(0.8)
Other	**(0.5)**	(0.2)	(0.8)
Effective income tax rate	**34.9%**	31.9%	33.0%

The increase in the Company's 2011 effective tax rate is primarily the result of decreases in non-taxable AFUDC equity and state tax credits. The decrease in the Company's 2010 effective tax rate from 2009 is primarily the result of an increase in non-taxable AFUDC equity, an increase in state tax credits earned on ongoing construction projects, and a decrease in tax deductions related to unrecognized tax benefits. See "Unrecognized Tax Benefits" herein for additional information on unrecognized tax benefits related to state tax credits.

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Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $190 million, resulting in a balance of $47 million as of December 31, 2011.

Changes during the year in unrecognized tax benefits were as follows:

	2011	2010	2009
		(in millions)	
Unrecognized tax benefits at beginning of year	**$237**	$181	$137
Tax positions from current periods	**9**	52	44
Tax positions increase from prior periods	**—**	27	6
Tax positions decrease from prior periods	**(87)**	(23)	(5)
Reductions due to settlements	**(112)**	—	—
Reductions due to expired statute of limitations	**—**	—	(1)
Balance at end of year	**$47**	$237	$181

The tax positions from current periods for 2011 relate primarily to the tax accounting method change for repairs-generation assets, and other miscellaneous tax positions. The tax positions decrease from prior periods and reductions due to settlements for 2011 relate to the settlement of the Georgia state tax credit litigation on June 10, 2011. See Note 3 under "Income Tax Matters – Georgia State Income Tax Credits" for additional information. In addition, the tax positions decrease from prior periods for 2011 also relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in millions)	
Tax positions impacting the effective tax rate	**$28**	$202	$181
Tax positions not impacting the effective tax rate	**19**	35	—
Balance of unrecognized tax benefits	**$47**	$237	$181

The tax positions impacting the effective tax rate for 2011 relate primarily to the production activities deduction and other miscellaneous tax positions. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See "Tax Method of Accounting for Repairs" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in millions)	
Interest accrued at beginning of year	**$27**	$20	$14
Interest reclassified due to settlements	**(24)**	—	—
Interest accrued during the year	**3**	7	6
Balance at end of year	**$6**	$27	$20

The Company classifies interest on tax uncertainties as interest expense. The interest for all years presented was primarily associated with the state tax credit litigation settled on June 10, 2011. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs - generation assets, as well as the conclusion or settlement of federal or state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

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The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $133 million for the Company. On August 19, 2011, the IRS issued a revenue procedure which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs - transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constituted substantially all of the assets of these trusts and were reflected in the balance sheet as long-term debt at December 31, 2010. The Company considered that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constituted a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2010, trust preferred securities of $200 million were outstanding. In September 2011, the Company redeemed all of the preferred securities and the related trust junior subordinated notes. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2011	2010
	(in millions)	
Capital lease	**$ 5**	$ 4
Bank term loans	**250**	300
Pollution control revenue bonds	**—**	8
Senior notes	**200**	100
Other long-term debt	**—**	3
Total	**$ 455**	$ 415

Maturities through 2016 applicable to total long-term debt are as follows: $455 million in 2012; $1.7 billion in 2013; $5 million in 2014; $256 million in 2015; and $260 million in 2016.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2011 and 2010 was $1.8 billion and $1.5 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

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Senior Notes

The Company issued $550 million aggregate principal amount of unsecured senior notes in 2011. The proceeds of the issuance were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2011 and 2010, the Company had $6.4 billion and $6.3 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $55 million and $59 million at December 31, 2011 and 2010, respectively.

Bank Term Loans

At December 31, 2011 and 2010, the Company had $450 million and $300 million of bank loans outstanding, respectively. At December 31, 2011, $200 million of the bank loans outstanding were short-term instruments and are reflected in notes payable on the balance sheet.

Subsequent to December 31, 2011, the Company entered into a six-month short-term floating rate bank loan in an aggregate principal amount of $100 million bearing interest based on one-month London Interbank Offered Rate (LIBOR).

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2011, the Company was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the Company. The Company is currently in compliance with all such covenants.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2011 and 2010, the Company had a capitalized lease obligation for its corporate headquarters building of $55 million and $58 million, respectively, with an interest rate of 7.4% and 8.0%, respectively. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the Class A preferred stock and preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

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Bank Credit Arrangements

At December 31, 2011, committed credit arrangements with banks were as follows:

Expires (a)			
2014	2016	Total	Unused
		(in millions)	
$250	$1,500	$1,750	$1,745

(a) No credit arrangements expire in 2012, 2013, or 2015.

The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes certain hybrid securities. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2011, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $1.7 billion of unused credit arrangements provides liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2011 was $868 million.

The Company has short-term borrowings primarily through a commercial paper program that has the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

Details of short-term borrowings, excluding $2 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$ 313	0.20%	$ 208	0.26%	$ 681
Short-term bank debt	200	1.18%	9	1.18%	200
Total	$ 513	0.51%	$ 217	0.33%	
December 31, 2010:					
Commercial paper	$ 575	0.30%	$ 167	0.325%	$ 575

(a) Average and maximum amounts are based upon daily balances during the period.

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7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $2.3 billion, $2.4 billion, and $2.1 billion for 2012, 2013, and 2014, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $237 million, $249 million, and $228 million for 2012, 2013, and 2014, respectively. In addition to these base level environmental expenditures there are other potential incremental environmental compliance investments that may be necessary to comply with the EPA's MATS rule and the proposed water and coal combustion byproducts rules. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2011, significant purchase commitments were outstanding in connection with the continuous construction program. See Note 3 under "Construction" for additional information on the portion of the Company's continuous construction program associated with new generation.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract. In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made quarterly based on actual operating hours of the respective units. Total payments to GE are currently estimated at $143 million over the remaining term of the LTSA, which is currently projected to be approximately seven years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has a LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $4.5 million. The contract contains cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense, as appropriate, net of any joint owner billings, based on the nature of the work.

The Company has entered into a LTSA with Mitsubishi Power Systems Americas, Inc. (MPS) for the purpose of providing certain parts and maintenance services for the three combined cycle units at Plant McDonough. Unit 4 went into service on December 28, 2011 and Units 5 and 6 are scheduled to go into service in May and November 2012, respectively. The LTSA stipulates that MPS will perform all planned maintenance on each covered unit which includes the cost of all materials and services. MPS is also obligated to cover costs of unplanned maintenance on the gas turbines subject to limits specified in the LTSA. This LTSA began in 2011 and is in effect through two major inspection cycles per covered unit. Periodic payments to MPS are to be made quarterly and will also be made based on the scheduled inspections for the respective covered units. Payments to MPS, which are subject to price escalation, are currently estimated to be $557 million for the term of this agreement which is expected to be 15 years. However, the LTSA contains various termination provisions at the option of the Company.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 2.7 million tons, equating to approximately $75 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $18 million in 2012, $18 million in 2013, $18 million in 2014, $10 million in 2015, and $3 million in 2016.

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Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2011.

Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2012	$ 546	$1,473	$ 257
2013	647	1,121	167
2014	501	494	163
2015	420	308	102
2016	406	153	71
2017 and thereafter	2,179	238	528
Total	$4,699	$3,787	$1,288

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $120 million, $106 million, and $82 million for the years 2011, 2010, and 2009, respectively.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

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Purchased Power Commitments

The Company has commitments regarding a portion of a 5% interest in Plant Vogtle owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $52 million, $55 million, and $54 million in 2011, 2010, and 2009, respectively. The Company also has entered into other various long-term PPAs. Estimated total long-term obligations under these commitments at December 31, 2011 were as follows:

	Vogtle Capacity Payments	Affiliated PPAs	Non-Affiliated PPAs
		(in millions)	
2012	$ 50	$108	$ 104
2013	23	109	111
2014	20	109	112
2015	11	109	121
2016	11	110	126
2017 and thereafter	78	275	1,493
Total	$193	$820	$2,067

- Certain PPAs reflected in the table are accounted for as operating leases.
- Excludes four PPAs that are subject to certification by the Georgia PSC. See Note 3 under "Retail Regulatory Matters – 2011 Integrated Resource Plan Update" for additional information.

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $33 million for 2011, $35 million for 2010, and $43 million for 2009.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2012	$27	$ 7	$ 34
2013	23	6	29
2014	18	5	23
2015	13	3	16
2016	8	1	9
2017 and thereafter	7	1	8
Total	$96	$23	$119

In addition to the above rental commitments, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These operating leases expire in 2014 and 2018 and the Company's maximum obligation is approximately $10 million and $24 million, respectively. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to a third party. Estimated annual commitments for the three-year lease and seven-year lease are approximately $1 million and $2 million, respectively. A portion of the rail car lease obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

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Guarantees

Alabama Power has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to rail car leases.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2011, there were 1,722 current and former employees of the Company participating in the stock option program, and there were 47 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

The Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2010	10,381,933	$32.44
Granted	1,264,485	37.99
Exercised	(3,686,300)	31.56
Cancelled	(7,531)	32.19
Outstanding at December 31, 2011	**7,952,587**	**$33.73**
Exercisable at December 31, 2011	**5,245,143**	**$33.42**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $100 million and $68 million, respectively.

As of December 31, 2011, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. The amounts were not material for any year presented.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $32 million, $12 million, and $2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises was not material for any of the years presented.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 185,512. During 2011, 168,748 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 28,302 performance share units were forfeited resulting in 325,958 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units and the related tax benefit recognized in income were not material. As of December 31, 2011, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months was not material.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests, is $237 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year.

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Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $69 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

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As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

As of December 31, 2011:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 13	$—	$ 13
Nuclear decommissioning trusts: [a]				
Domestic equity	143	1	—	144
Foreign equity	100	—		100
U.S. Treasury and government agency securities	—	25	—	25
Municipal bonds	—	82	—	82
Corporate bonds	—	167	—	167
Mortgage and asset backed securities	—	123	—	123
Other investments	—	25	—	25
Cash equivalents	13	—	—	13
Total	$ 256	$ 436	$—	$ 692
Liabilities:				
Energy-related derivatives	$ —	$ 95	$—	$ 95

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

As of December 31, 2010:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 1	$—	$ 1
Nuclear decommissioning trusts: [a]				
Domestic equity	257	1	—	258
U.S. Treasury and government agency securities	—	213	—	213
Municipal bonds	—	53	—	53
Corporate bonds	—	138	—	138
Mortgage and asset backed securities	—	89	—	89
Other investments	—	67	—	67
Total	$ 257	$ 562	$—	$ 819
Liabilities:				
Energy-related derivatives	$ —	$ 101	$—	$ 101

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear

Decommissioning" for additional information.

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Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, implied volatility, and LIBOR interest rates. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then used in the valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2011:	*(in millions)*			
Nuclear decommissioning trusts:				
Corporate bonds — commingled funds	$32	None	Daily	1 to 3 days
Other — commingled funds	25	None	Daily	Not applicable
As of December 31, 2010:				
Nuclear decommissioning trusts:				
Corporate bonds — commingled funds	$65	None	Daily	1 to 3 days
Other — commingled funds	67	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds – commingled funds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2011	**$8,418**	**$9,209**
2010	$8,285	$8,548

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

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11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2011, the net volume of energy-related derivative contracts for natural gas positions totaled 73 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu for the Company.

Interest Rate Derivatives

The Company also enters into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2011 and 2010, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 are not expected to have a material impact on the Company's financial statements. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

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Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 8**	$ 1	Liabilities from risk management activities	**$ 68**	$ 77
	Other deferred charges and assets	**5**	—	Other deferred credits and liabilities	**27**	24
Total derivatives designated as hedging instruments for regulatory purposes		**$ 13**	$ 1		**$ 95**	$101

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (68)**	$ (77)	Other regulatory liabilities, current	**$ 8**	$ 1
	Other regulatory assets, deferred	**(27)**	(24)	Other deferred credits and liabilities	**5**	—
Total energy-related derivative gains (losses)		**$ (95)**	$(101)		**$ 13**	$ 1

The pre-tax effect of gains (losses) related to interest rate derivatives designated as cash flow hedging instruments recognized in OCI was not material for any year presented. Gains (losses) reclassified from accumulated OCI into income were as follows:

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

	Amount		
Statements of Income Location	**2011**	2010	2009
		(in millions)	
Interest expense, net of amounts capitalized	**$ (4)**	$ (16)	$(22)

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

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Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2011, the fair value of derivative liabilities with contingent features was $13 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2011	**$1,989**	**$393**	**$ 206**
June 2011	**2,265**	**537**	**309**
September 2011	**2,788**	**895**	**520**
December 2011	**1,758**	**222**	**110**
March 2010	$1,984	$399	$ 238
June 2010	2,000	411	238
September 2010	2,628	714	420
December 2010	1,737	141	54

The Company’s business is influenced by seasonal weather conditions.

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	2011	2010	2009	2008	2007
Operating Revenues (in millions)	**$ 8,800**	$ 8,349	$ 7,692	$ 8,412	$ 7,572
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 1,145**	$ 950	$ 814	$ 903	$ 836
Cash Dividends on Common Stock (in millions)	**$ 1,096**	$ 820	$ 739	$ 721	$ 690
Return on Average Common Equity (percent)	**12.89**	11.42	11.01	13.56	13.50
Total Assets (in millions)	**$ 27,151**	$ 25,914	$ 24,295	$ 22,316	$ 20,823
Gross Property Additions (in millions)	**$ 1,981**	$ 2,401	$ 2,646	$ 1,953	$ 1,862
Capitalization (in millions):					
Common stock equity	**$ 9,023**	$ 8,741	$ 7,903	$ 6,879	$ 6,435
Preferred and preference stock	**266**	266	266	266	266
Long-term debt	**8,018**	7,931	7,782	7,006	5,938
Total (excluding amounts due within one year)	**$ 17,307**	$ 16,938	$ 15,951	$ 14,151	$ 12,639
Capitalization Ratios (percent):					
Common stock equity	**52.1**	51.6	49.5	48.6	50.9
Preferred and preference stock	**1.5**	1.6	1.7	1.9	2.1
Long-term debt	**46.4**	46.8	48.8	49.5	47.0
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,047,390**	2,049,770	2,043,661	2,039,503	2,024,520
Commercial	**296,143**	296,140	295,375	295,925	295,478
Industrial	**8,279**	8,136	8,202	8,248	8,240
Other	**7,521**	7,309	6,580	5,566	4,807
Total	**2,359,333**	2,361,355	2,353,818	2,349,242	2,333,045
Employees (year-end)	**8,310**	8,330	8,599	9,337	9,270

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011 (continued)
Georgia Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions):					
Residential	**$ 3,241**	$ 3,072	$ 2,686	$ 2,648	$ 2,443
Commercial	**3,217**	3,011	2,826	2,917	2,576
Industrial	**1,547**	1,441	1,318	1,640	1,404
Other	**94**	84	82	81	75
Total retail	**8,099**	7,608	6,912	7,286	6,498
Wholesale — non-affiliates	**341**	380	395	569	538
Wholesale — affiliates	**32**	53	112	286	278
Total revenues from sales of electricity	**8,472**	8,041	7,419	8,141	7,314
Other revenues	**328**	308	273	271	258
Total	**$ 8,800**	$ 8,349	$ 7,692	$ 8,412	$ 7,572
Kilowatt-Hour Sales (in millions):					
Residential	**27,223**	29,433	26,272	26,412	26,840
Commercial	**32,900**	33,855	32,593	33,058	33,057
Industrial	**23,519**	23,209	21,810	24,164	25,490
Other	**657**	663	671	671	697
Total retail	**84,299**	87,160	81,346	84,305	86,084
Wholesale — non-affiliates	**3,904**	4,662	5,208	9,755	10,578
Wholesale — affiliates	**626**	1,000	2,504	3,695	5,192
Total	**88,829**	92,822	89,058	97,755	101,854
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.91**	10.44	10.22	10.03	9.10
Commercial	**9.78**	8.89	8.67	8.82	7.79
Industrial	**6.58**	6.21	6.04	6.79	5.51
Total retail	**9.61**	8.73	8.50	8.64	7.55
Wholesale	**8.23**	7.65	6.57	6.36	5.17
Total sales	**9.54**	8.66	8.33	8.33	7.18
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,288**	14,367	12,848	12,969	13,315
Residential Average Annual Revenue Per Customer	**$ 1,582**	$ 1,499	$ 1,314	$ 1,300	$ 1,212
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**16,588**	15,992	15,995	15,995	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	**14,800**	15,614	15,173	14,221	13,817
Summer	**16,941**	17,152	16,080	17,270	17,974
Annual Load Factor (percent)	**59.5**	60.9	60.7	58.4	57.5
Plant Availability (percent):					
Fossil-steam	**88.6**	88.6	92.5	91.0	90.8
Nuclear	**92.2**	94.0	88.4	89.8	92.4
Source of Energy Supply (percent):					
Coal	**44.4**	51.8	52.3	58.7	61.5
Nuclear	**16.6**	16.4	16.2	14.8	14.6
Hydro	**1.1**	1.4	1.8	0.6	0.5
Oil and gas	**8.9**	8.0	7.7	5.1	5.5
Purchased power -					
From non-affiliates	**6.1**	5.2	4.4	5.1	3.8
From affiliates	**22.9**	17.2	17.6	15.7	14.1
Total	**100.0**	100.0	100.0	100.0	100.0

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GULF POWER COMPANY

FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2011 Annual Report

The management of Gulf Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

/s/ Mark A. Crosswhite
Mark A. Crosswhite
President and Chief Executive Officer

/s/ Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer

February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the "Company") (a wholly owned subsidiary of The Southern Company) as of December 31, 2011 and 2010, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-302 to II-341) referred to above present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 24, 2012

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2011 Annual Report

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, and storm restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

On July 8, 2011, the Company filed a petition with the Florida Public Service Commission (PSC) requesting an increase in retail rates and charges to the extent necessary to generate additional gross annual revenues in the amount of $93.5 million. The requested increase is expected to provide a reasonable opportunity for the Company to earn a retail rate of return on common equity of 11.7%. The Florida PSC is expected to make a decision on this matter in the first quarter 2012.

On August 23, 2011, the Florida PSC approved the Company's request for an interim retail rate increase of $38.5 million per year, to be operative beginning with billings based on meter readings on and after September 22, 2011 and continuing through the effective date of the Florida PSC's decision on the Company's petition for the permanent increase. The interim rates are subject to refund pending the outcome of the permanent retail base rate proceeding.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 430,000 customers, the Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2011 Peak Season EFOR of 1.24% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2011 was better than the target for these reliability measures.

Net income after dividends on preference stock is the primary measure of the Company's financial performance. The performance for net income after dividends on preference stock in 2011 was above target. The target net income was lower than the prior year's target due to increasing costs and reduced revenue growth due to the current economic environment, which were the primary drivers in the Company's decision to file a rate case in 2011. The Company's 2011 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season EFOR	**4.80% or less**	**1.24%**
Net income after dividends on preference stock	**$101.6 million**	**$105.0 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis the Company places on reliability, customer satisfaction, and financial integrity, as well as the commitment shown by employees in achieving or exceeding management's expectations.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2011 Annual Report

Earnings

The Company's 2011 net income after dividends on preference stock was $105.0 million, a decrease of $16.5 million from the previous year. In 2010, net income after dividends on preference stock was $121.5 million, an increase of $10.3 million from the previous year. The decrease in net income after dividends on preference stock in 2011 was primarily due to an increase in other operations and maintenance expenses in 2011 and closer to normal weather in 2011 compared to 2010, partially offset by higher wholesale capacity revenues from non-affiliates. The increase in net income after dividends on preference stock in 2010 was primarily due to increased retail revenues due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010 when compared to the corresponding periods in 2009.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$1,519.8**	**$(70.4)**	$288.0
Fuel	**662.3**	**(80.0)**	168.9
Purchased power	**90.5**	**(6.7)**	5.2
Other operations and maintenance	**311.3**	**30.7**	20.3
Depreciation and amortization	**129.7**	**8.2**	28.1
Taxes other than income taxes	**101.3**	**(0.5)**	7.3
Total operating expenses	**1,295.1**	**(48.3)**	229.8
Operating income	**224.7**	**(22.1)**	58.2
Total other income and (expense)	**(52.2)**	**(4.6)**	(29.4)
Income taxes	**61.3**	**(10.2)**	18.5
Net income	**111.2**	**(16.5)**	10.3
Dividends on preference stock	**6.2**	**—**	—
Net income after dividends on preference stock	**$ 105.0**	**$(16.5)**	$ 10.3

Operating Revenues

Operating revenues for 2011 were $1,519.8 million, reflecting a decrease of $70.4 million from 2010. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2011	2010
	(in millions)	
Retail — prior year	**$1,308.7**	$1,106.6
Estimated change in –		
Rates and pricing	**2.0**	72.7
Sales growth (decline)	**3.9**	(2.3)
Weather	**(17.8)**	18.7
Fuel and other cost recovery	**(88.3)**	113.0
Retail — current year	**1,208.5**	1,308.7
Wholesale revenues –		
Non-affiliates	**133.6**	109.2
Affiliates	**111.3**	110.0
Total wholesale revenues	**244.9**	219.2
Other operating revenues	**66.4**	62.3
Total operating revenues	**$1,519.8**	$1,590.2
Percent change	**(4.4)%**	22.1%

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2011 Annual Report

Retail revenues decreased $100.2 million, or 7.7%, in 2011 compared to 2010 primarily as a result of lower fuel revenues and lower energy sales due to closer to normal weather in 2011 compared to 2010, partially offset by an increase related to interim retail rate revenues. Retail revenues increased $202.1 million, or 18.3%, in 2010 compared to 2009 primarily as a result of higher fuel and purchased power expenses in 2010 and revenues associated with higher projected environmental compliance costs in 2010. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Revenues associated with changes in rates and pricing include cost recovery provisions for energy conservation costs, environmental compliance costs, and interim retail revenues. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for additional information.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. For 2010, fuel and other cost recovery provisions also include the change in revenues related to 2009 recovery of storm damage restoration costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Note 1 to the financial statements under "Revenues" and "Property Damage Reserve" and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Total wholesale revenues were $244.9 million in 2011, an increase of $25.7 million, or 11.7%, compared to 2010 primarily due to a 41.6% increase in capacity revenues resulting from higher capacity rates. Total wholesale revenues were $219.2 million in 2010, an increase of $93.0 million, or 73.7%, compared to 2009 primarily to serve weather-related increases in affiliate demand as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010.

Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation.

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to other utilities in Florida and Georgia. Wholesale revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy is generally sold at variable cost. The capacity and energy components under these unit power sales contracts were as follows:

	2011	2010	2009
		(in thousands)	
Unit power sales –			
Capacity	**$ 52,507**	$ 33,482	$24,466
Energy	**44,227**	31,379	33,122
Total	**96,734**	64,861	57,588
Other power sales –			
Capacity and other	**10,717**	11,158	11,060
Energy	**26,104**	33,153	25,457
Total	**36,821**	44,311	36,517
Total non-affiliated	**$133,555**	$109,172	$94,105

Revenues from unit power sales increased $31.9 million, or 49.1%, in 2011 primarily due to a 56.8% increase in capacity revenues related to higher capacity rates as a result of contracts effective June 2010. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource. The increase in unit power sales was also due to increased energy revenues related to a 31.3% increase in kilowatt-hour (KWH) sales. Revenues from other power sales decreased $7.5 million, or 16.9%, in 2011 primarily due to decreased energy revenues related to a 9.6% decrease in KWH sales. Revenues from unit power sales increased $7.3 million, or 12.6%, in 2010 primarily due to increased capacity revenues as a result of new contracts.

Revenues from other power sales increased $7.8 million, or 21.3%, in 2010 primarily due to increased KWH sales to serve weather-related increases in non-territorial demand.

Wholesale revenues from affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in the Company's fuel cost recovery clause.

Other operating revenues increased $4.1 million, or 6.7%, in 2011 primarily due to a $3.4 million increase in revenues from other energy services. Other operating revenues decreased $7.2 million, or 10.4%, in 2010 primarily due to a $10.3 million decrease in revenues from other energy services, partially offset by higher franchise fees of $3.1 million. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses. Franchise fees have no impact on net income.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2011 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in millions)				
Residential	**5,305**	**(6.1)%**	7.6%	**0.5%**	(0.2)%
Commercial	**3,911**	**(2.1)**	2.6	**0.0**	0.3
Industrial	**1,799**	**6.7**	(2.4)	**6.7**	(2.4)
Other	**25**	**(0.7)**	1.9	**(0.7)**	1.9
Total retail	**11,040**	**(2.8)**	(4.2)	**1.3%**	(0.3)%
Wholesale					
Non-affiliates	**2,013**	**20.2**	(7.6)		
Affiliates	**2,608**	**7.0**	180.0		
Total wholesale	**4,621**	**12.4**	53.2		
Total energy sales	**15,661**	**1.2%**	13.9%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales and commercial KWH sales decreased in 2011 compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Weather-adjusted 2011 KWH sales to residential and commercial customers remained relatively flat as compared to 2010. Residential KWH sales and commercial KWH sales increased in 2010 compared to 2009 primarily due to significantly colder weather in the first quarter 2010 and warmer weather in the third quarter 2010 when compared to the corresponding periods in 2009. Weather-adjusted 2010 KWH sales to residential and commercial customers remained relatively flat as compared to 2009.

Industrial KWH sales increased 6.7% in 2011 compared to 2010 primarily resulting from the addition of a new large customer and higher customer load requirements and production levels. Industrial KWH sales decreased 2.4% in 2010 compared to 2009 primarily resulting from increased customer co-generation due to the lower cost of natural gas in 2010.

Wholesale KWH sales to non-affiliates increased 20.2% in 2011 compared to 2010 primarily resulting from higher KWHs scheduled by unit power customers. Wholesale KWH sales to non-affiliates decreased 7.6% in 2010 compared to 2009 primarily resulting from lower KWHs scheduled by unit power customers.

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Wholesale KWH sales to affiliates increased 7.0% in 2011 compared to 2010 primarily resulting from the Company's lower priced natural gas resources available to serve affiliate demand. Wholesale KWH sales to affiliates increased 180% in 2010 compared to 2009 primarily to serve weather-related increases in affiliate demand due to colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's electricity generated and purchased were as follows:

	2011	**2010**	**2009**
Total generation *(millions of KWHs)*	**12,035**	13,440	12,895
Total purchased power *(millions of KWHs)*	**4,349**	2,858	1,481
Sources of generation *(percent)* –			
Coal	**67%**	78%	69%
Gas	**33**	22	31
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.97**	5.10	4.27
Gas	**4.06**	4.68	4.66
Average cost of fuel, generated *(cents per net KWH)*	**4.67**	5.01	4.39
Average cost of purchased power *(cents per net KWH*)*	**4.39**	5.82	6.71

* Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Total fuel and purchased power expenses were $752.8 million in 2011, a decrease of $86.7 million, or 10.3%, from the prior year costs. The net decrease in fuel and purchased power expenses was due to a $103.2 million decrease in the average cost of fuel and purchased power and a $70.3 million decrease related to KWHs generated, partially offset by an $86.8 million increase related to KWHs purchased. Total fuel and purchased power expenses were $839.5 million in 2010, an increase of $174.1 million, or 26.2%, from the prior year costs. The net increase in fuel and purchased power expenses was primarily due to a $116.3 million increase related to total KWHs generated and purchased and a $57.8 million increase in the cost of energy resulting primarily from an increase in the average cost of coal-fired generation and affiliated company power purchases.

Fuel expense was $662.3 million in 2011, a decrease of $80.0 million, or 10.8%, from the prior year costs. This decrease was primarily the result of a 13.3% decrease in the average cost of natural gas per KWH generated, a change in the source of generation to be more heavily weighted to lower cost, natural gas-fired generation, and a 10.5% decrease in KWHs generated as a result of lower demand. These decreases were partially offset by a 52.2% increase in KWHs purchased. Fuel expense was $742.3 million in 2010, an increase of $168.9 million, or 29.5%, from the prior year costs. This increase was primarily the result of a 19.4% increase in the average cost of coal per KWH generated and a 4.2% increase in KWHs generated as a result of higher demand.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions between the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. Purchased power expense was $90.5 million in 2011, a decrease of $6.7 million, or 6.9%, from the prior year costs. This decrease was due to net decreases of $4.9 million in capacity costs and $1.8 million in energy costs. Purchased power expense was $97.2 million in 2010, an increase of $5.2 million, or 5.7%, from the prior year costs. This increase was due to a $15.0 million increase in capacity costs, offset by a $9.8 million decrease in energy costs.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2011 Annual Report

The 2011 average cost of purchased power decreased 24.6% in 2011 compared to the prior period primarily as a result of a decrease in the average cost of natural gas. The 2010 average cost of purchased power decreased 13.3% compared to the prior period primarily as a result of an increase in the volume of KWHs purchased.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Other Operations and Maintenance Expenses

In 2011, other operations and maintenance expenses increased $30.7 million, or 11.0%, compared to the prior year primarily due to increases of $13.9 million in routine and planned outage maintenance expense at generation facilities, $3.2 million in other energy services, $10.4 million in labor expense, and $2.1 million in marketing programs. In 2010, other operations and maintenance expenses increased $20.3 million, or 7.8%, compared to the prior year primarily due to a $20.2 million increase in routine and planned outage maintenance expense at generation facilities.

Depreciation and Amortization

Depreciation and amortization increased $8.2 million, or 6.7%, in 2011 compared to the prior year primarily due to the addition of environmental control projects and other net additions to transmission and distribution facilities. Depreciation and amortization increased $28.1 million, or 30.1%, in 2010 compared to the prior year primarily due to the addition of an environmental control project at Plant Crist being placed into service in December 2009 and other net additions to generation and distribution facilities. Approximately $19.0 million of the 2010 increase was related to the environmental control project at Plant Crist and was recovered through the environmental clause; therefore, it had no material impact on net income.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $0.5 million, or 0.5%, in 2011 compared to the prior year primarily due to a $1.1 million decrease in gross receipts taxes, partially offset by a $0.7 million increase in property taxes. Taxes other than income taxes increased $7.3 million, or 7.7%, in 2010 compared to the prior year primarily due to a $5.5 million increase in gross receipts taxes and franchise fees and a $1.0 million increase in payroll taxes. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity increased $2.7 million, or 37.4%, in 2011 compared to the prior year primarily due to construction of environmental control projects at generating facilities. AFUDC equity decreased $16.6 million, or 69.7%, in 2010 compared to the prior year primarily due to an environmental control project at Plant Crist being placed into service in December 2009. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $6.3 million, or 12.0%, in 2011 compared to the prior year primarily due to increases in long-term debt levels resulting from the issuance of additional senior notes in 2011. These increases were partially offset as a result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects. Interest expense, net of amounts capitalized increased $13.5 million, or 35.3%, in 2010 compared to the prior year as the result of a reduction in capitalized interest for an environmental control project at Plant Crist being placed into service in December 2009. The increased interest was also primarily due to an increase in long-term debt levels resulting from the issuance of additional senior notes in 2010 to fund general corporate purposes, including the Company's continuous construction program.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2011 Annual Report

Income Taxes

Income taxes decreased $10.2 million, or 14.3%, in 2011 compared to the prior year primarily due to lower pre-tax earnings. Income taxes increased $18.5 million, or 34.9%, in 2010 compared to the prior year primarily as a result of higher earnings before income taxes and a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

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New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the Company had invested approximately $1.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $141 million, $136 million, and $343 million for 2011, 2010, and 2009, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $523 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$200	$137	$186

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $400 million as described below.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could be approximately $1.8 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is approximately $400 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $375 million from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $105 million over the same 2012 through 2014 three-year period. These estimates are based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rules. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	Up to $45	Up to $90	Up to $240
Proposed water and coal combustion byproducts rules	Up to $5	Up to $25	Up to $75
Total potential incremental environmental compliance investments	**Up to $50**	**Up to $115**	**Up to $315**

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The Company's compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Company's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As of December 31, 2011, the Company had total generating capacity of approximately 2,663 MWs, of which 2,060 MWs are coal-fired. Over the past several years, the Company has installed various pollution control technologies on its coal-fired units, including both selective catalytic reduction equipment and scrubbers on two of its largest coal units making up 705 MWs of the Company's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Company is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including on the units with existing pollution control technologies), and changing fuel sources for certain units. Also see "PSC Matters – Environmental Cost Recovery" for information regarding potential construction of a scrubber on Plant Daniel Units 1 and 2, which are co-owned by the Company.

The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The environmental cost recovery mechanism in Florida is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company spent approximately $1.1 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. The 2008 standard is expected to result in designation of new nonattainment areas within the Company's service territory and could require additional reductions in NO_x emissions.

The EPA also regulates fine particulate matter emissions on an annual and 24-hour average basis. Although all areas within the Company's service territory have air quality levels that attain the current standard, the EPA has announced its intention to propose new, more stringent annual and 24-hour fine particulate matter standards in mid- 2012.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operation costs.

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Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Company's service territory were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the States of Florida, Georgia, and Mississippi.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the Company's facilities which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, and the MATS rule on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. In addition, certain units in the State of Georgia, including Plant Scherer Unit 3, which is co-owned by the Company, are required to install specific emissions controls according to a schedule set forth in the state's Multi-Pollutant Rule, which is designed to reduce emissions of SO_2, NO_x, and mercury.

The ultimate outcome of these matters cannot be determined at this time.

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Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs, as described above, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

In addition, the State of Florida is finalizing numeric nutrient water quality standards to limit the amount of nitrogen and phosphorous allowed in state waters. The impact of these standards will depend on the specific requirements of the final rule and cannot be determined at this time. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Coal Combustion Byproducts

The Company currently operates three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the Company sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Florida, Georgia, and Mississippi each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described above, that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See Note 3 to the Financial Statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

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Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 13 million metric tons of carbon dioxide equivalent.

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The preliminary estimate of the Company's 2011 greenhouse gas emissions is approximately 10 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company continues to evaluate its future energy and emissions profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

PSC Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On July 8, 2011, the Company filed a petition with the Florida PSC requesting an increase in retail rates to the extent necessary to generate additional gross annual revenues in the amount of $93.5 million. The requested increase is expected to provide a reasonable opportunity for the Company to earn a retail rate of return on common equity of 11.7%. The Florida PSC is expected to make a decision on this matter in the first quarter 2012.

On August 23, 2011, the Florida PSC approved the Company's request for an interim retail rate increase of $38.5 million per year, effective beginning with billings based on meter readings on and after September 22, 2011 and continuing through the effective date of the Florida PSC's decision on the Company's petition for the permanent increase. The interim rates are subject to refund pending the outcome of the permanent retail base rate proceeding.

The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

On November 1, 2011, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2012. The net effect of the approved changes is a 1.1% rate decrease for residential customers using 1,000 KWHs per month. On February 14, 2012, the Florida PSC approved an additional reduction to the fuel cost recovery factors for the remainder of 2012, starting in March 2012. The effect of the approved change is a 2.7% decrease for residential customers using 1,000 KWHs per month. The billing factors for 2012 are intended to allow the Company to recover projected 2012 costs as well as refund or collect the 2011 over or under recovered amounts in 2012. Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters" respectively, for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved the Company's additional request to further reduce an estimated December 2012 over recovery balance of approximately $32 million.

The change in the fuel cost under recovered balance to an over recovered balance during 2011 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2011, the over recovered fuel balance was approximately $9.9 million, which is included in other regulatory liabilities, current in the balance sheets. At December 31, 2010, the under recovered fuel balance was approximately $17.4 million, which is included in under recovered regulatory clause revenues, current in the balance sheets. See Note 1 to the financial statements under "Fuel Costs" and "Fuel Inventory" for additional information.

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Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2011 and 2010, the Company had an over recovered purchased power capacity balance of approximately $8.0 million and $4.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See Note 7 to the financial statements under "Fuel and Purchased Power Commitments" for additional information.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the Florida Department of Environmental Protection for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that were implemented in the 2007 through 2011 timeframe. In April 2010, the Company filed an update to the plan, which was approved by the Florida PSC in November 2010. The Florida PSC acknowledged that the costs associated with the Company's CAIR and CAVR compliance plans are eligible for recovery through the environmental cost recovery clause. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2011 and 2010, the over recovered environmental balance was approximately $10.0 million and $10.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 7 to the financial statements under "Construction Program" for additional information.

In July 2010, Mississippi Power Company (Mississippi Power) filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, and it is scheduled for completion in late 2015. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the Energy Conservation Cost Recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

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See BUSINESS under "Rate Matters – Integrated Resource Planning – Gulf Power" in Item 1 for a discussion of the Company's 10-year site plan filed on an annual basis with the Florida PSC.

At December 31, 2011, the under recovered energy conservation balance was approximately $3.1 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2010, the over recovered energy conservation balance was approximately $2.9 million, which is included in other regulatory liabilities, current in the balance sheets.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Consequently, it is estimated there will be a positive cash flow benefit of between $100 million and $120 million in 2012.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the

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Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.1 million or less change in total benefit expense and a $13 million or less change in projected obligations.

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FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to add environmental equipment for existing generating units and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012.

Net cash provided from operating activities totaled $376.2 million, $267.8 million, and $194.2 million for 2011, 2010, and 2009, respectively. The $108.4 million increase in net cash provided from operating activities in 2011 was primarily due to a $42.4 million increase related to the recovery of fuel costs and a $51.6 million increase from prepaid income taxes, primarily due to bonus depreciation. The $73.5 million increase in net cash provided from operating activities in 2010 was primarily due to a $99.2 million increase from deferred income taxes related to bonus depreciation and a $90.9 million decrease in fuel inventory, partially offset by a $109.4 million increase in accounts receivable related to fuel cost and a $25.7 million decrease related to the qualified pension plan.

Net cash used for investing activities totaled $343.5 million, $308.4 million, and $468.4 million for 2011, 2010, and 2009, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $337.8 million, $285.4 million, and $450.4 million for 2011, 2010, and 2009, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $31.8 million for 2011. Net cash provided from financing activities totaled $48.4 million and $279.4 million for 2010 and 2009, respectively. The $80.2 million decrease in cash from financing activities in 2011 was primarily due to a $175.0 million reduction in senior notes issuances in 2011, partially offset by a $104.9 million reduction in redemption of senior notes and other long-term debt in 2011. The $231.0 million decrease in net cash provided from financing activities in 2010 was due primarily to $194.4 million higher issuances of pollution control revenue bonds and common stock in 2009 and a net $54.3 million decrease in senior notes outstanding.

Significant balance sheet changes in 2011 include an increase of $234.3 million in property, plant, and equipment, primarily due to the addition of environmental control projects; an increase in other regulatory assets, deferred and other deferred credits and liabilities of $103.2 million and $54.1 million, respectively, primarily due to increases in power purchase agreements (PPAs) deferred capacity expense; an increase of $76.1 million in accumulated deferred income taxes, primarily due to bonus depreciation; and the issuance of common stock to Southern Company for $50 million.

The Company's ratio of common equity to total capitalization, including short-term debt, was 43.7% in 2011 and 43.1% in 2010. See Note 6 to the financial statements for additional information.

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Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term indebtedness, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2011, the Company had approximately $17.3 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires				Executable Term-Loans	
2012	2014	Total	Unused	One Year	Two Years
$75	$165	$240	$240	$75	$—

(a) No credit arrangements expire in 2013, 2015, or 2016.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants.

During the second quarter 2011, the Company reviewed its lines of credit and made changes resulting in a temporary net increase of $40 million. In the third quarter 2011, the Company repaid a $30 million draw and decreased the amount of bank credit arrangements to $240 million. The Company also replaced $165 million of credit arrangements having one-year expirations with $165 million of credit arrangements having terms of three years. The Company expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2011, the Company had $69 million outstanding of pollution control revenue bonds requiring liquidity support. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

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Details of short-term borrowings, excluding $3.6 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$111	0.22%	$53	0.24%	$111
Short-term bank debt	—	—	4	1.31%	30
Total	$111	0.22%	$57	0.32%	
December 31, 2010:					
Commercial paper	$92	0.29%	$44	0.25%	$108

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In January 2011, the Company issued to Southern Company 500,000 shares of the Company's common stock, without par value, and realized proceeds of $50 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In May 2011, the Company issued $125 million aggregate principal amount of Series 2011A 5.75% Senior Notes due June 1, 2051. The net proceeds from the sale of the Series 2011A Senior Notes were used to repay a $110 million bank note, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2011, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2011 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 125
Below BBB- and/or Baa3	540

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Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including but not limited to market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt at December 31, 2011 was 0.12%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $693,000 at January 1, 2012. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to natural gas purchases, the Company continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(11,228)**	$(13,687)
Contracts realized or settled	**11,004**	17,613
Current period changes [(a)]	**(40,561)**	(15,154)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(40,785)**	$(11,228)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was a decrease of $29.6 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, the Company had a net hedge volume of 37.5 million mmBtu with a weighted average swap contract cost approximately $1.14 per mmBtu above market prices and a net hedge volume of 19.6 million mmBtu at December 31, 2010 with a weighted average swap contract cost approximately $0.67 per mmBtu above market prices. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2011 and 2010, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

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The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in thousands)			
Level 1	**$ —**	**$ —**	**$ —**	**$ —**
Level 2	**(40,785)**	**(22,632)**	**(16,798)**	**(1,355)**
Level 3	**—**	**—**	**—**	**—**
Fair value of contracts outstanding at end of period	**$(40,785)**	**$(22,632)**	**$(16,798)**	**$(1,355)**

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as detailed below. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could be approximately $1.8 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is approximately $400 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules. The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	**2013**	**2014**
Construction program:		*(in millions)*	
Base capital	$ 202	$151	$ 179
Existing environmental statutes and regulations	200	137	186
Total construction program base level capital investment	**$ 402**	**$288**	**$ 365**
Potential incremental environmental compliance investments:			
MATS rule	Up to $45	Up to $90	Up to $240
Proposed water and coal combustion byproducts rules	Up to $5	Up to $25	Up to $75
Total potential incremental environmental compliance investments	**Up to $50**	**Up to $115**	**Up to $ 315**

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The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing [d]	Total
			(in thousands)			
Long-term debt [a] –						
Principal	$ —	$ 135,000	$110,000	$1,000,318	$ —	$1,245,318
Interest	58,036	113,462	103,502	760,552	—	1,035,552
Energy-related derivative obligations [b]	22,786	16,841	1,356	—	—	40,983
Preference stock dividends [c]	6,203	12,405	12,405	—	—	31,013
Operating leases	21,542	37,852	2,087	523	—	62,004
Unrecognized tax benefits and interest [d]	—	—	—	—	3,175	3,175
Purchase commitments [e] –						
Capital [f]	402,090	653,064	—	—	—	1,055,154
Limestone [g]	6,747	14,006	14,715	23,481	—	58,949
Coal	177,262	—	—	—	—	177,262
Natural gas [h]	128,969	286,050	207,864	176,530	—	799,413
Purchased power [i]	44,709	117,417	185,362	592,761	—	940,249
Long-term service agreements [j]	6,632	13,764	14,461	9,179	—	44,036
Pension and other postretirement benefit plans [k]	3,789	8,300	—	—	—	12,089
Total	$878,765	$1,408,161	$651,752	$2,563,344	$ 3,175	$5,505,197

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2012, as reflected in the statements of capitalization.

(b) For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) The timing related to the realization of $3.2 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2011, 2010, and 2009 were $311 million, $280 million, and $260 million, respectively.

(f) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $50 million, up to $115 million, and up to $315 million for 2012, 2013, and 2014, respectively. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce SO_2 emissions from its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(i) The capacity and transmission related costs associated with power purchase agreements (PPA) are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

(j) Long-term service agreements include price escalation based on inflation indices.

(k) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, economic recovery, projections for the qualified pension plan and postretirement benefit plan, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings or inquiries, including the pending EPA civil action against the Company and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010, and 2009
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	2011	2010	2009
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 1,208,490**	$ 1,308,726	$ 1,106,568
Wholesale revenues, non-affiliates	**133,555**	109,172	94,105
Wholesale revenues, affiliates	**111,346**	110,051	32,095
Other revenues	**66,421**	62,260	69,461
Total operating revenues	**1,519,812**	1,590,209	1,302,229
Operating Expenses:			
Fuel	**662,283**	742,322	573,407
Purchased power, non-affiliates	**48,882**	41,278	23,706
Purchased power, affiliates	**41,612**	55,948	68,276
Other operations and maintenance	**311,358**	280,585	260,274
Depreciation and amortization	**129,651**	121,498	93,398
Taxes other than income taxes	**101,302**	101,778	94,506
Total operating expenses	**1,295,088**	1,343,409	1,113,567
Operating Income	**224,724**	246,800	188,662
Other Income and (Expense):			
Allowance for equity funds used during construction	**9,914**	7,213	23,809
Interest expense, net of amounts capitalized	**(58,150)**	(51,897)	(38,358)
Other income (expense), net	**(4,012)**	(2,888)	(3,652)
Total other income and (expense)	**(52,248)**	(47,572)	(18,201)
Earnings Before Income Taxes	**172,476**	199,228	170,461
Income taxes	**61,268**	71,514	53,025
Net Income	**111,208**	127,714	117,436
Dividends on Preference Stock	**6,203**	6,203	6,203
Net Income After Dividends on Preference Stock	**$ 105,005**	$ 121,511	$ 111,233

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Gulf Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Net Income After Dividends on Preference Stock	**$ 105,005**	$ 121,511	$ 111,233
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(542), and $1,132, respectively	**—**	(863)	1,803
Reclassification adjustment for amounts included in net income, net of tax of $360, $376, and $419, respectively	**573**	598	667
Total other comprehensive income (loss)	**573**	(265)	2,470
Comprehensive Income	**$ 105,578**	$ 121,246	$ 113,703

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
Gulf Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Operating Activities:			
Net income	**$ 111,208**	$ 127,714	$ 117,436
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**135,790**	127,897	99,564
Deferred income taxes	**63,228**	82,681	(16,545)
Allowance for equity funds used during construction	**(9,914)**	(7,213)	(23,809)
Pension, postretirement, and other employee benefits	**(356)**	(23,964)	1,769
Stock based compensation expense	**1,318**	1,101	933
Hedge settlements	**—**	1,530	—
Other, net	**(8,258)**	(4,126)	(5,173)
Changes in certain current assets and liabilities —			
-Receivables	**21,518**	(36,687)	83,245
-Prepayments	**10,150**	(10,796)	(192)
-Fossil fuel stock	**17,519**	15,766	(75,145)
-Materials and supplies	**(5,073)**	(6,251)	(1,642)
-Prepaid income taxes	**26,901**	(29,630)	(6,355)
-Property damage cost recovery	**—**	—	10,746
-Other current assets	**40**	55	(12)
-Accounts payable	**(2,528)**	15,683	7,890
-Accrued taxes	**1,475**	1,427	(2,404)
-Accrued compensation	**25**	5,122	(6,330)
-Over recovered regulatory clause revenues	**10,247**	3,192	11,215
-Other current liabilities	**2,937**	4,279	(960)
Net cash provided from operating activities	**376,227**	267,780	194,231
Investing Activities:			
Property additions	**(324,372)**	(285,793)	(421,309)
Investment in restricted cash from pollution control revenue bonds	**—**	—	(49,188)
Distribution of restricted cash from pollution control revenue bonds	**—**	6,347	42,841
Cost of removal net of salvage	**(14,471)**	(1,145)	(9,751)
Construction payables	**2,902**	(21,581)	(23,603)
Payments pursuant to long-term service agreements	**(8,007)**	(6,011)	(7,421)
Other investing activities	**420**	(262)	(5)
Net cash used for investing activities	**(343,528)**	(308,445)	(468,436)
Financing Activities:			
Increase (decrease) in notes payable, net	**21,324**	4,451	(49,599)
Proceeds —			
Common stock issued to parent	**50,000**	50,000	135,000
Capital contributions from parent company	**2,101**	2,242	22,032
Pollution control revenue bonds	**—**	21,000	130,400
Senior notes	**125,000**	300,000	140,000
Redemptions —			
Senior notes	**(608)**	(215,515)	(1,214)
Other long-term debt	**(110,000)**	—	—
Payment of preference stock dividends	**(6,203)**	(6,203)	(6,203)
Payment of common stock dividends	**(110,000)**	(104,300)	(89,300)
Other financing activities	**(3,419)**	(3,253)	(1,677)
Net cash provided from (used for) financing activities	**(31,805)**	48,422	279,439
Net Change in Cash and Cash Equivalents	**894**	7,757	5,234
Cash and Cash Equivalents at Beginning of Year	**16,434**	8,677	3,443
Cash and Cash Equivalents at End of Year	**$ 17,328**	$ 16,434	$8,677
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $3,951, $2,875 and $9,489 capitalized, respectively)	**$ 55,486**	$ 42,521	$40,336
Income taxes (net of refunds)	**(26,345)**	17,224	73,889

Noncash decrease in notes payable related to energy services	**—**	—	(8,309)
Noncash transactions — accrued property additions at year-end	**19,439**	14,475	42,050

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
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Assets	**2011**	2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 17,328**	$ 16,434
Receivables —		
Customer accounts receivable	**72,754**	74,377
Unbilled revenues	**49,921**	64,697
Under recovered regulatory clause revenues	**5,530**	19,690
Other accounts and notes receivable	**13,350**	9,867
Affiliated companies	**14,844**	7,859
Accumulated provision for uncollectible accounts	**(1,962)**	(2,014)
Fossil fuel stock, at average cost	**147,567**	167,155
Materials and supplies, at average cost	**49,781**	44,729
Other regulatory assets, current	**35,849**	20,278
Prepaid expenses	**28,327**	58,412
Other current assets	**2,051**	3,585
Total current assets	**435,340**	485,069
Property, Plant, and Equipment:		
In service	**3,846,446**	3,634,255
Less accumulated provision for depreciation	**1,124,291**	1,069,006
Plant in service, net of depreciation	**2,722,155**	2,565,249
Construction work in progress	**287,173**	209,808
Total property, plant, and equipment	**3,009,328**	2,775,057
Other Property and Investments	**16,394**	16,352
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**48,210**	46,357
Prepaid pension costs	**—**	7,291
Other regulatory assets, deferred	**323,116**	219,877
Other deferred charges and assets	**39,493**	34,936
Total deferred charges and other assets	**410,819**	308,461
Total Assets	**$3,871,881**	$3,584,939

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
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Liabilities and Stockholder's Equity	**2011**	2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ —**	$ 110,000
Notes payable	**114,507**	93,183
Accounts payable —		
Affiliated	**54,874**	46,342
Other	**63,265**	68,840
Customer deposits	**35,779**	35,600
Accrued taxes —		
Accrued income taxes	**1,362**	3,835
Other accrued taxes	**12,114**	7,944
Accrued interest	**14,018**	13,393
Accrued compensation	**14,485**	14,459
Other regulatory liabilities, current	**35,639**	27,060
Liabilities from risk management activities	**22,786**	9,415
Other current liabilities	**22,916**	19,766
Total current liabilities	**391,745**	449,837
Long-Term Debt (See accompanying statements)	**1,235,447**	1,114,398
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**458,978**	382,876
Accumulated deferred investment tax credits	**6,760**	8,109
Employee benefit obligations	**109,740**	76,654
Other cost of removal obligations	**214,598**	204,408
Other regulatory liabilities, deferred	**44,843**	42,915
Other deferred credits and liabilities	**186,824**	132,708
Total deferred credits and other liabilities	**1,021,743**	847,670
Total Liabilities	**2,648,935**	2,411,905
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**1,124,948**	1,075,036
Total Liabilities and Stockholder's Equity	**$3,871,881**	$3,584,939
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CAPITALIZATION
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	2011	2010	**2011**	2010
	(in thousands)		*(percent of total)*	
Long Term Debt:				
Long-term notes payable —				
4.35% due 2013	**$ 60,000**	$ 60,000		
4.90% due 2014	**75,000**	75,000		
5.30% due 2016	**110,000**	110,000		
4.75% to 5.90% due 2017-2051	**691,363**	566,971		
Variable rates (0.71% at 1/1/11) due 2011	**—**	110,000		
Total long-term notes payable	**936,363**	921,971		
Other long-term debt —				
Pollution control revenue bonds —				
1.75% to 6.00% due 2022-2049	**239,625**	239,625		
Variable rates (0.12% to 0.16% at 1/1/12) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	308,955		
Unamortized debt discount	**(9,871)**	(6,528)		
Total long-term debt (annual interest requirement — $58.0 million)	**1,235,447**	1,224,398		
Less amount due within one year	**—**	110,000		
Long-term debt excluding amount due within one year	**1,235,447**	1,114,398	**50.2%**	48.7%
Preferred and Preference Stock:				
Authorized - 20,000,000 shares—preferred stock				
- 10,000,000 shares—preference stock				
Outstanding - $100 par or stated value — 6% preference stock	**53,886**	53,886		
— 6.45% preference stock	**44,112**	44,112		
- 1,000,000 shares (non-cumulative)				
Total preference stock (annual dividend requirement — $6.2 million)	**97,998**	97,998	**4.0**	4.3
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized - 20,000,000 shares				
Outstanding - 2011: 4,142,717 shares				
Outstanding - 2010: 3,642,717 shares	**353,060**	303,060		
Paid-in capital	**542,709**	538,375		
Retained earnings	**231,333**	236,328		
Accumulated other comprehensive income (loss)	**(2,154)**	(2,727)		
Total common stockholder's equity	**1,124,948**	1,075,036	**45.8**	47.0
Total Capitalization	**$2,458,393**	$2,287,432	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)		
Balance at December 31, 2008	1,793	$118,060	$511,547	$ 197,417	$ (4,932)	$ 822,092
Net income after dividends on preference stock	—	—	—	111,233	—	111,233
Issuance of common stock	1,350	135,000	—	—	—	135,000
Capital contributions from parent company	—	—	23,030	—	—	23,030
Other comprehensive income (loss)	—	—	—	—	2,470	2,470
Cash dividends on common stock	—	—	—	(89,300)	—	(89,300)
Change in benefit plan measurement date	—	—	—	(233)	—	(233)
Balance at December 31, 2009	3,143	253,060	534,577	219,117	(2,462)	1,004,292
Net income after dividends on preference stock	—	—	—	121,511	—	121,511
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	3,798	—	—	3,798
Other comprehensive income (loss)	—	—	—	—	(265)	(265)
Cash dividends on common stock	—	—	—	(104,300)	—	(104,300)
Balance at December 31, 2010	**3,643**	**303,060**	**538,375**	**236,328**	**(2,727)**	**1,075,036**
Net income after dividends on preference stock	**—**	**—**	**—**	**105,005**	**—**	**105,005**
Issuance of common stock	**500**	**50,000**	**—**	**—**	**—**	**50,000**
Capital contributions from parent company	**—**	**—**	**4,334**	**—**	**—**	**4,334**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**573**	**573**
Cash dividends on common stock	**—**	**—**	**—**	**(110,000)**	**—**	**(110,000)**
Balance at December 31, 2011	**4,143**	**$353,060**	**$542,709**	**$ 231,333**	**$ (2,154)**	**$1,124,948**

The accompanying notes are an integral part of these financial statements.

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NOTES TO FINANCIAL STATEMENTS
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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies — the Company, Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), and Mississippi Power Company (Mississippi Power) — are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $97 million, $99 million, and $87 million during 2011, 2010, and 2009, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $6.7 million, $8.9 million, and $3.9 million and Mississippi Power $23.4 million, $25.0 million, and $20.9 million in 2011, 2010, and 2009, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a power purchase agreement (PPA) with Southern Power for a total of approximately 292 megawatts (MWs) annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $14.3 million, $14.5 million, and $12.4 million in 2011, 2010, and 2009, respectively, and fuel costs associated with the PPA were $1.8 million, $3.3 million, and $0.4 million in 2011, 2010, and 2009, respectively. These costs have been approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. Additionally, the Company had $4.2 million of deferred capacity expenses included in prepaid expenses and other regulatory liabilities, current in the balance sheets at December 31, 2011 and 2010, respectively. See Note 7 under "Fuel and Purchased Power Commitments" for additional information.

The Company has an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $2.4 million, $2.4 million, and $1.4 million in 2011, 2010, and 2009, respectively, for its share of related expenses.

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The Company has an agreement with Alabama Power under which Alabama Power will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $138.5 million for the entire project. These costs are estimated to begin in 2012 and will continue through 2023. These costs have been approved for recovery by the Florida PSC through the Company's purchase power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any significant services to or from affiliates in 2010 or 2009. In 2011, the Company provided storm restoration assistance to Alabama Power totaling $1.4 million. The Company did not receive any significant services in 2011.

The traditional operating companies, including the Company, and Southern Power jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Commitments" for additional information.

In 2010, the Company purchased an assembly fluted compressor from Georgia Power and an unbucketed turbine rotor from Southern Power for $3.9 million and $6.3 million, respectively. The Company also sold a universal distance piece to Southern Power, a compressor rotor and blades to Georgia Power, and a turbine rotor and blades to Mississippi Power for $0.6 million, $3.9 million, and $6.2 million, respectively. There were no significant affiliate transactions for 2011 or 2009.

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Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2011	2010	Note
	(in thousands)		
Deferred income tax charges	**$ 44,533**	$ 42,352	(a)
Deferred income tax charges — Medicare subsidy	**4,005**	4,332	(b)
Asset retirement obligations	**(5,653)**	(4,310)	(a,j)
Other cost of removal obligations	**(214,598)**	(204,408)	(a)
Deferred income tax credits	**(8,113)**	(9,362)	(a)
Loss on reacquired debt	**14,437**	15,874	(c)
Vacation pay	**8,973**	8,288	(d,j)
Under recovered regulatory clause revenues	**3,133**	17,437	(e)
Over recovered regulatory clause revenues	**(27,950)**	(17,703)	(e)
Property damage reserve	**(30,473)**	(27,593)	(f)
Fuel-hedging (realized and unrealized) losses	**43,071**	15,024	(g,j)
Fuel-hedging (realized and unrealized) gains	**(197)**	(2,376)	(g,j)
PPA charges	**94,986**	52,404	(j,k)
Generation site selection/evaluation costs	**20,415**	12,814	(l)
Other assets	**1,675**	833	(e,j)
Environmental remediation	**61,625**	61,749	(h,j)
PPA credits	**(7,536)**	(7,536)	(j,k)
Other liabilities	**(798)**	(930)	(f)
Retiree benefit plans, net	**116,091**	74,930	(i,j)
Total assets (liabilities), net	**$ 117,626**	$ 31,819	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years. See Note 5 under "Current and Deferred Income Taxes" for additional information.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

(d) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 15 years. Includes $239 thousand related to other postretirement benefits. See Note 2 and Note 5 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Recovered over the life of the PPA for periods up to 14 years.

(l) Deferred pursuant to Florida Statute while the Company continues to evaluate certain potential new generation projects.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates.

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Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under “Retail Regulatory Matters” for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are “more likely than not” of being sustained upon examination by the appropriate taxing authorities. See Note 5 under “Unrecognized Tax Benefits” for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company’s property, plant, and equipment in service consisted of the following at December 31:

	2011	2010
	(in thousands)	
Generation	**$2,283,494**	$2,157,619
Transmission	**368,542**	337,055
Distribution	**1,030,546**	982,022
General	**161,322**	154,762
Plant acquisition adjustment	**2,542**	2,797
Total plant in service	**$3,846,446**	$3,634,255

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed.

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Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2011, 3.5% in 2010, and 3.1% in 2009. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2011	2010
	(in thousands)	
Balance at beginning of year	**$ 11,470**	$12,608
Liabilities incurred	**106**	—
Liabilities settled	**(1,050)**	(1,794)
Accretion	**545**	656
Cash flow revisions	**(342)**	—
Balance at end of year	**$ 10,729**	$11,470

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 7.65% for each of the years 2011, 2010, and 2009. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 11.75%, 7.39%, and 26.64% for 2011, 2010, and 2009, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For

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assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC-approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $25.1 million and $36.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2011, 2010, and 2009. As of December 31, 2011 and 2010, the balance in the Company's property damage reserve totaled approximately $30.5 million and $27.6 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. Such a surcharge was authorized in 2005 after Hurricane Ivan in 2004 and was extended by a 2006 Florida PSC order approving a stipulation to address costs incurred as a result of Hurricanes Dennis and Katrina in 2005. Under the 2006 Florida PSC order, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company would be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism. After the effective date of new base rates, the Company will retain the right to request relief on an expedited basis from the Florida PSC without the thresholds set forth in the stipulation.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $2.7 million and $2.0 million at December 31, 2011 and 2010, respectively. For 2011, $1.6 million and $1.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2010, $1.6 million and $0.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There are no liabilities in excess of the reserve balance at December 31, 2011. Liabilities in excess of the reserve balance of $0.8 million at December 31, 2010 were included in deferred credits and other liabilities in the balance sheet. There were no corresponding regulatory assets at December 31, 2011. Corresponding regulatory assets of $0.8 million at December 31, 2010 are included in current assets in the balance sheet.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

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Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC-approved fuel hedging program. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2011.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income after preference stock dividends, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2012, no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.53%	5.93%
Other postretirement benefit plans	**4.88**	5.41	5.84
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**8.11**	8.18	8.36

* Net of estimated investment management expenses of 30 basis points.

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The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2011 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$3,446	$ (2,943)
Service and interest costs	223	(191)

Pension Plans

The total accumulated benefit obligation for the pension plans was $321 million at December 31, 2011 and $290 million at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 316,286**	$ 298,886
Service cost	**8,431**	7,853
Interest cost	**17,074**	17,305
Benefits paid	**(13,807)**	(13,401)
Plan amendments	**—**	460
Actuarial loss (gain)	**24,850**	5,183
Balance at end of year	**352,834**	316,286
Change in plan assets		
Fair value of plan assets at beginning of year	**307,828**	254,059
Actual return (loss) on plan assets	**9,552**	38,736
Employer contributions	**751**	28,434
Benefits paid	**(13,807)**	(13,401)
Fair value of plan assets at end of year	**304,324**	307,828
Accrued liability	**$ (48,510)**	$(8,458)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $336 million and $17 million, respectively. All pension plan assets are related to the qualified pension plan.

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Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in thousands)	
Prepaid pension costs	**$ —**	$ 7,291
Other regulatory assets	**115,853**	75,096
Current liabilities, other	**(794)**	(778)
Employee benefit obligations	**(47,716)**	(14,971)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2012.

	2011	2010	Estimated Amortization in 2012
		(in thousands)	
Prior service cost	**$ 6,402**	$ 7,664	**$1,262**
Net (gain) loss	**109,451**	67,432	**3,913**
Other regulatory assets	**$115,853**	$75,096	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2009	$ 85,194
Net (gain) loss	(8,857)
Change in prior service costs	459
Reclassification adjustments:	
Amortization of prior service costs	(1,302)
Amortization of net gain (loss)	(398)
Total reclassification adjustments	(1,700)
Total change	(10,098)
Balance at December 31, 2010	$ 75,096
Net (gain) loss	**42,531**
Change in prior service costs	**—**
Reclassification adjustments:	
Amortization of prior service costs	**(1,262)**
Amortization of net gain (loss)	**(512)**
Total reclassification adjustments	**(1,774)**
Total change	**40,757**
Balance at December 31, 2011	**$ 115,853**

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Components of net periodic pension cost were as follows:

	2011	2010	2009
		(in thousands)	
Service cost	**$ 8,431**	$ 7,853	$ 6,478
Interest cost	**17,074**	17,305	17,139
Expected return on plan assets	**(27,232)**	(24,695)	(24,357)
Recognized net (gain) loss	**512**	398	224
Net amortization	**1,262**	1,302	1,478
Net periodic pension cost	**$ 47**	$ 2,163	$ 962

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2012	$ 15,372
2013	15,950
2014	16,655
2015	17,315
2016	18,045
2017 to 2021	104,528

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 69,617**	$ 72,640
Service cost	**1,132**	1,304
Interest cost	**3,658**	4,121
Benefits paid	**(4,189)**	(4,068)
Actuarial (gain) loss	**292**	(4,704)
Plan amendments	**—**	—
Retiree drug subsidy	**413**	324
Balance at end of year	**70,923**	69,617
Change in plan assets		
Fair value of plan assets at beginning of year	**15,697**	14,973
Actual return (loss) on plan assets	**514**	2,010
Employer contributions	**2,543**	2,458
Benefits paid	**(3,776)**	(3,744)
Fair value of plan assets at end of year	**14,978**	15,697
Accrued liability	**$(55,945)**	$(53,920)

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Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in thousands)	
Regulatory assets	**$ 239**	$ —
Regulatory liabilities	**—**	(166)
Current liabilities, other	**(624)**	(211)
Employee benefit obligations	**(55,321)**	(53,709)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in thousands)	
Prior service cost	**$ 510**	$ 695	**$186**
Net (gain) loss	**(464)**	(1,311)	**—**
Transition obligation	**193**	450	**193**
Regulatory assets (liabilities)	**$ 239**	$ (166)	

The changes in the balance of regulatory assets and regulatory liabilities related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets	**Regulatory Liabilities**
	(in thousands)	
Balance at December 31, 2009	$ 5,861	$ —
Net (gain) loss	(5,455)	(166)
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	(257)	—
Amortization of prior service costs	(186)	—
Amortization of net gain (loss)	37	—
Total reclassification adjustments	(406)	—
Total change	(5,861)	(166)
Balance at December 31, 2010	$ —	$(166)
Net (gain) loss	**635**	**166**
Change in prior service costs/transition obligation	**—**	**—**
Reclassification adjustments:		
Amortization of transition obligation	**(257)**	**—**
Amortization of prior service costs	**(186)**	**—**
Amortization of net gain (loss)	**47**	**—**
Total reclassification adjustments	**(396)**	**—**
Total change	**239**	**166**
Balance at December 31, 2011	**$ 239**	**$ —**

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Components of the other postretirement benefit plans' net periodic cost were as follows:

	2011	2010	2009
		(in thousands)	
Service cost	**$ 1,132**	$ 1,304	$ 1,328
Interest cost	**3,658**	4,121	4,705
Expected return on plan assets	**(1,445)**	(1,481)	(1,436)
Net amortization	**396**	406	548
Net postretirement cost	**$ 3,741**	$ 4,350	$ 5,145

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in thousands)	
2012	$ 4,475	$ (481)	$ 3,994
2013	4,684	(537)	4,147
2014	4,927	(597)	4,330
2015	5,146	(661)	4,485
2016	5,354	(729)	4,625
2017 to 2021	27,719	(3,924)	23,795

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**—**	—
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**28%**	28%
International equity	24	**24**	26
Domestic fixed income	26	**26**	25
Special situations	3	**—**	—
Real estate investments	13	**13**	12
Private equity	9	**9**	9
Total	100%	**100%**	100%

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The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

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The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 51,686	$ 23,857	$ —	$ 75,543
International equity*	53,130	15,223	—	68,353
Fixed income:				
U.S. Treasury, government, and agency bonds	—	19,375	—	19,375
Mortgage- and asset-backed securities	—	6,047	—	6,047
Corporate bonds	—	37,274	120	37,394
Pooled funds	—	16,998	—	16,998
Cash equivalents and other	30	6,228	—	6,258
Real estate investments	9,838	—	34,989	44,827
Private equity	—	—	26,053	26,053
Total	$114,684	$125,002	$61,162	$300,848

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 57,023	$ 23,012	$ 31	$ 80,066
International equity*	57,515	19,940	—	77,455
Fixed income:				
U.S. Treasury, government, and agency bonds	—	13,703	—	13,703
Mortgage- and asset-backed securities	—	11,122	—	11,122
Corporate bonds	—	26,760	92	26,852
Pooled funds	—	9,063	—	9,063
Cash equivalents and other	92	21,537	—	21,629
Real estate investments	8,295	—	30,355	38,650
Private equity	—	—	28,727	28,727
Total	$122,925	$125,137	$59,205	$307,267
Liabilities:				
Derivatives	(31)	—	—	(31)
Total	$122,894	$125,137	$59,205	$307,236

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in thousands)			
Beginning balance	**$30,355**	**$28,727**	$24,699	$25,053
Actual return on investments:				
Related to investments held at year end	**3,021**	**(538)**	2,596	2,954
Related to investments sold during the year	**896**	**1,941**	810	810
Total return on investments	**3,917**	**1,403**	3,406	3,764
Purchases, sales, and settlements	**717**	**(4,077)**	2,250	(90)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$34,989**	**$26,053**	$30,355	$28,727

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$2,445	$1,128	$ —	$ 3,573
International equity*	2,511	719	—	3,230
Fixed income:				
U.S. Treasury, government, and agency bonds	—	918	—	918
Mortgage- and asset-backed securities	—	286	—	286
Corporate bonds	—	1,761	—	1,761
Pooled funds	—	1,328	—	1,328
Cash equivalents and other	1	295	—	296
Real estate investments	466	—	1,657	2,123
Private equity	—	—	1,232	1,232
Total	$5,423	$6,435	$2,889	$14,747

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2010:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$2,727	$1,100	$ 1	$ 3,828
International equity*	2,751	955	—	3,706
Fixed income:				
U.S. Treasury, government, and agency bonds	—	655	—	655
Mortgage- and asset-backed securities	—	533	—	533
Corporate bonds	—	1,280	—	1,280
Pooled funds	—	953	—	953
Cash equivalents and other	3	1,030	—	1,033
Real estate investments	396	—	1,452	1,848
Private equity	—	—	1,375	1,375
Total	$5,877	$6,506	$2,828	$15,211

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in thousands)		
Beginning balance	**$1,452**	**$1,375**	$1,326	$1,346
Actual return on investments:				
Related to investments held at year end	**129**	**(26)**	30	—
Related to investments sold during the year	**42**	**77**	40	34
Total return on investments	**171**	**51**	70	34
Purchases, sales, and settlements	**34**	**(194)**	56	(5)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$1,657**	**$1,232**	$1,452	$1,375

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $3.7 million, $3.6 million, and $3.7 million, respectively.

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3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case.

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The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2011, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $61.6 million. For 2011, approximately $2.4 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $59.2 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, there was no impact on net income as a result of these liabilities.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On July 8, 2011, the Company filed a petition with the Florida PSC requesting an increase in retail rates to the extent necessary to generate additional gross annual revenues in the amount of $93.5 million. The requested increase is expected to provide a reasonable opportunity for the Company to earn a retail rate of return on common equity of 11.7%. The Florida PSC is expected to make a decision on this matter in the first quarter 2012.

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On August 23, 2011, the Florida PSC approved the Company's request for an interim retail rate increase of $38.5 million per year, effective beginning with billings based on meter readings on and after September 22, 2011 and continuing through the effective date of the Florida PSC's decision on the Company's petition for the permanent increase. The interim rates are subject to refund pending the outcome of the permanent retail base rate proceeding.

The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

On November 1, 2011, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2012. The net effect of the approved changes is a 1.1% rate decrease for residential customers using 1,000 KWHs per month. On February 14, 2012, the Florida PSC approved an additional reduction to the fuel cost recovery factors for the remainder of 2012, starting in March 2012. The effect of the approved change is a 2.7% decrease for residential customers using 1,000 KWHs per month. The billing factors for 2012 are intended to allow the Company to recover projected 2012 costs as well as refund or collect the 2011 over or under recovered amounts in 2012. Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved the Company's additional request to further reduce an estimated December 2012 over recovery balance of approximately $32 million.

The change in the fuel cost under recovered balance to an over recovered balance during 2011 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2011, the over recovered fuel balance was approximately $9.9 million, which is included in other regulatory liabilities, current in the balance sheets. At December 31, 2010, the under recovered fuel balance was approximately $17.4 million, which is included in under recovered regulatory clause revenues, current in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2011 and 2010, the Company had an over recovered purchased power capacity balance of approximately $8.0 million and $4.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

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In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that were implemented in the 2007 through 2011 timeframe. In April 2010, the Company filed an update to the plan, which was approved by the Florida PSC in November 2010. The Florida PSC acknowledged that the costs associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2011 and 2010, the over recovered environmental balance was approximately \$10.0 million and \$10.4 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

In July 2010, Mississippi Power filed a request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately \$660 million, and it is scheduled for completion in late 2015. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the Energy Conservation Cost Recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

At December 31, 2011, the under recovered energy conservation balance was approximately \$3.1 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2010, the over recovered energy conservation balance was approximately \$2.9 million, which is included in other regulatory liabilities, current in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's proportionate share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.

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At December 31, 2011, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$366,747(a)	$270,690
Accumulated depreciation	110,308	157,684
Construction work in progress	2,256	27,544
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $2.5 million.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in thousands)	
Federal -			
Current	**$ (1,548)**	$(14,115)	$ 62,980
Deferred	**56,087**	77,452	(14,453)
	54,539	63,337	48,527
State -			
Current	**(412)**	2,948	6,590
Deferred	**7,141**	5,229	(2,092)
	6,729	8,177	4,498
Total	**$61,268**	$ 71,514	$ 53,025

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	**$496,392**	$413,490
Fuel recovery clause	**—**	7,062
Pension and other employee benefits	**25,268**	23,990
Regulatory assets associated with employee benefit obligations	**44,871**	29,054
Regulatory assets associated with asset retirement obligations	**4,345**	4,646
Other	**14,804**	15,793
Total	**585,680**	494,035
Deferred tax assets-		
Federal effect of state deferred taxes	**16,684**	14,757
Postretirement benefits	**16,769**	20,723
Fuel recovery clause	**2,531**	—
Pension and other employee benefits	**49,116**	33,047
Property reserve	**13,159**	12,712
Other comprehensive loss	**1,353**	1,712
Asset retirement obligations	**4,345**	4,646
Alternative minimum tax carryforward	**7,151**	—
Other	**20,191**	19,727
Total	**131,299**	107,324
Net deferred tax liabilities	**454,381**	386,711
Portion included in current assets (liabilities), net	**4,597**	(3,835)
Accumulated deferred income taxes	**$458,978**	$382,876

At December 31, 2011, the tax-related regulatory assets to be recovered from customers were $48.5 million. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized AFUDC. In 2010, the Company deferred $4.5 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The Company will amortize the regulatory asset to amortization expense over the remaining average service life of 14 years. Amortization amounted to $0.3 million in 2011.

At December 31, 2011, the tax-related regulatory liabilities to be credited to customers were $8.1 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.3 million in 2011, $1.5 million in 2010, and $1.6 million in 2009. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had been utilized.

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

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Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.7	1.7
Non-deductible book depreciation	**0.5**	0.3	0.3
Difference in prior years' deferred and current tax rate	**(0.3)**	(0.3)	(0.4)
Production activities deduction	**—**	—	(0.9)
AFUDC equity	**(2.0)**	(1.3)	(4.9)
Other, net	**(0.2)**	(0.5)	0.3
Effective income tax rate	**35.5%**	35.9%	31.1%

The decrease in the 2011 effective tax rate is primarily the result of an increase in AFUDC equity, which is not taxable.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $1.0 million, resulting in a balance of $2.9 million as of December 31, 2011.

Changes during the year in unrecognized tax benefits were as follows:

	2011	2010	2009
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 3,870**	$1,639	$ 294
Tax positions from current periods	**540**	1,027	455
Tax positions from prior periods	**(1,518)**	1,204	890
Reductions due to settlements	**—**	—	—
Reductions due to expired statute of limitations	**—**	—	—
Balance at end of year	**$ 2,892**	$3,870	$1,639

The tax positions increase from current periods for 2011 relate primarily to the tax accounting method change for repairs-generation assets. The tax positions decrease from prior periods for 2011 also relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in thousands)	
Tax positions impacting the effective tax rate	**$1,804**	$1,826	$1,639
Tax positions not impacting the effective tax rate	**1,088**	2,044	—
Balance of unrecognized tax benefits	**$2,892**	$3,870	$1,639

The tax positions impacting the effective tax rate for 2011 relate primarily to the production activities deduction. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See "Tax Method of Accounting for Repairs" herein for additional information.

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Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in thousands)	
Interest accrued at beginning of year	**$210**	$ 90	$ 17
Interest reclassified due to settlements	**—**	—	—
Interest accrued during the year	**73**	120	73
Balance at end of year	**$283**	$210	$ 90

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010-2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $8 million for the Company. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs - generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Securities Due Within One Year

At December 31, 2011, the Company had no securities due within one year.

Maturities through 2016 applicable to total long-term debt are as follows: $60 million in 2013; $75 million in 2014; and $110 million in 2016. There are no scheduled maturities in 2012 and 2015.

Senior Notes

At December 31, 2011 and 2010, the Company had a total of $936.4 million and $812.0 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company which totaled approximately $41 million at December 31, 2011.

In May 2011, the Company issued $125 million aggregate principal amount of Series 2011A 5.75% Senior Notes due June 1, 2051. The net proceeds from the sale of the Series 2011A Senior Notes were used to repay a $110 million bank note, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

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Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. At December 31, 2011 and 2010, the Company had a total of $309 million and $309 million of outstanding pollution control revenue bonds, respectively, and is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2011. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, one series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2011, the Company issued to Southern Company 500,000 shares of the Company's common stock, without par value, and realized proceeds of $50 million. On January 20, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2011, committed credit arrangements with banks were as follows:

Expires [(a)]				Executable Term-Loans	
2012	2014	Total	Unused	One Year	Two Years
$75	$165	$240	$240	$75	$—

(a) No credit arrangements expire in 2013, 2015, or 2016.

During 2011, the Company reviewed its lines of credit and replaced $165 million of credit arrangements having one-year expirations with $165 million of credit arrangements having terms of three years. The Company expects to renew its credit arrangements, as needed, prior to expiration. During the second quarter 2011, the Company reviewed its lines of credit and made changes resulting in a temporary net increase of $40 million. In the third quarter 2011, the Company repaid a $30 million draw and decreased the amount of bank credit arrangements to $240 million. Of the $240 million of unused credit arrangements, $69 million provides support for variable rate pollution control revenue bonds and $171 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. Annual commitment fees average less than $^1/_4$ of 1% for the Company.

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Certain credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65%, as defined in the arrangements. At December 31, 2011, the Company was in compliance with these covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the Company defaulted on indebtedness over a specified threshold. The cross default provisions are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings, excluding $3.6 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$111	0.22%	$53	0.24%	$111
Short-term bank debt	—	N/A	4	1.31%	30
Total	$111	0.22%	$57	0.32%	
December 31, 2010:					
Commercial paper	$ 92	0.29%	$44	0.25%	$108

(a) Average and maximum amounts are based upon daily balances during the period.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $402 million, $288 million, and $365 million for 2012, 2013, and 2014, respectively. These amounts include capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $200 million, $137 million, and $186 million for 2012, 2013, and 2014, respectively. In addition to these base level environmental expenditures there are other potential incremental environmental compliance investments that may be necessary to comply with the EPA's final Mercury and Air Toxics Standards rule and the proposed water and coal combustion byproducts rules. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. The Company does not have any significant new generating capacity under construction. Construction of new transmission and distribution facilities and other capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, are ongoing.

Long-Term Service Agreements

The Company has a long-term service agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for a combined cycle generating facility. The LTSA provides that GE will perform all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in the LTSA.

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In general, the LTSA is in effect through two major inspection cycles of the unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Total remaining payments to GE under the LTSA for facilities owned are currently estimated at $44.0 million over the remaining life of the LTSA, which is currently estimated to be up to six years. However, the LTSA contains various cancellation provisions at the option of the Company.

Payments made under the LTSA prior to the performance of any planned inspections are recorded as prepayments. These amounts are included in deferred charges and other assets in the balance sheets for 2011 and 2010. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 0.7 million tons, equating to approximately $59 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $6.7 million in 2012, $6.9 million in 2013, $7.1 million in 2014, $7.3 million in 2015, and $7.4 million in 2016. Limestone costs are recovered through the environmental cost recovery clause.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2011. Also, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments		
	Purchased Power*	Natural Gas	Coal
		(in thousands)	
2012	$ 44,709	$128,969	$177,262
2013	49,485	153,186	—
2014	67,932	132,864	—
2015	92,808	106,581	—
2016	92,554	101,283	—
2017 and thereafter	592,761	176,530	—
Total	$940,249	$799,413	$177,262

* Included above is $173.6 million in obligations with affiliated companies. Certain PPAs are accounted for as operating leases.

Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

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Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Rental expenses related to these operating leases totaled $21.9 million, $23.1 million, and $10.1 million for 2011, 2010, and 2009, respectively.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Barges & Rail Cars	Other	Total
		(in thousands)	
2012	$21,022	$520	$21,542
2013	19,530	233	19,763
2014	17,958	131	18,089
2015	1,147	—	1,147
2016	940	—	940
2017 and thereafter	523	—	523
Total	$61,120	$884	$62,004

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum rail cars for the transportation of coal to Plant Daniel. The Company has the option to purchase the rail cars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other rail cars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $2.6 million in 2011, $3.5 million in 2010, and $4.0 million in 2009. The Company's annual railcar lease payments for 2012 through 2016 will average approximately $2.1 million and after 2016, lease payments total in aggregate approximately $0.5 million.

The Company has other operating lease agreements for aluminum rail cars for transportation of coal to Plant Scholz and to the Alabama State Docks located in Mobile, Alabama. At the Alabama State Docks this coal is transferred from the railcar to barge for transportation to Plant Crist and Plant Smith. The Company has the option to renew the leases at the end of each lease term. The Company's lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, were $4.3 million in 2011, $3.9 million in 2010, and $4.0 million in 2009. The Company's annual railcar lease payments for 2012 through 2014 will average approximately $3.0 million.

The Company has operating lease agreements for barges and tow boats for the transport of coal to Plants Crist and Smith. The Company has the option to renew the leases at the end of each lease term. The Company's lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, were $12.8 million in 2011, $13.5 million in 2010, and none in 2009. The Company's annual barge and tow boat lease payments for 2012 through 2014 will average approximately $13.6 million.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2011, there were 276 current and former employees of the Company participating in the stock option program, and there were 47 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

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The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term.

Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

The Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2010	1,735,965	$32.47
Granted	242,530	38.08
Exercised	(479,832)	31.33
Cancelled	—	—
Outstanding at December 31, 2011	**1,498,663**	**$33.75**
Exercisable at December 31, 2011	**906,637**	**$33.55**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $18.8 million and $11.6 million, respectively.

As of December 31, 2011, there was $0.4 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $0.7 million, $0.8 million, and $0.9 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.4 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $3.2 million, $1.6 million, and $0.2 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.2 million, $0.6 million, and $0.1 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 35,568. During 2011, 31,457 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 363 performance share units were forfeited resulting in 66,662 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units and the related tax benefit recognized in income were not material. As of December 31, 2011, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months was not material.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 198	$—	$ 198
Cash equivalents	13,949	—	—	13,949
Total	$13,949	$ 198	$—	$14,147
Liabilities:				
Energy-related derivatives	$ —	$40,983	$—	$40,983

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As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 2,380	$ —	$ 2,380
Cash equivalents	11,770	—	—	11,770
Total	$ 11,770	$ 2,380	$ —	$14,150
Liabilities:				
Energy-related derivatives	$ —	$ 13,608	$ —	$13,608

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice Period**
As of December 31, 2011:	*(in thousands)*			
Cash equivalents:				
Money market funds	$13,949	None	Daily	Not applicable
As of December 31, 2010:				
Cash equivalents:				
Money market funds	$11,770	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company’s investment in the money market funds.

As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	**Fair Value**
	(in thousands)	
Long-term debt:		
2011	**$1,235,447**	**$1,350,237**
2010	$1,224,398	$1,258,428

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

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10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2011, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in thousands)		
37,500	2017	—

* mmBtu — million British thermal units

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Interest Rate Derivatives

The Company also enters into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2011, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 are $0.9 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives were reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$154**	$1,801	Liabilities from risk management activities	**$22,786**	$ 9,415
	Other deferred charges and assets	**44**	575	Other deferred credits and liabilities	**18,197**	4,193
Total derivatives designated as hedging instruments for regulatory purposes		**$198**	$2,376		**$40,983**	$13,608
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ —**	$ 4	Liabilities from risk management activities	**$ —**	$ —
Total		**$198**	$2,380		**$40,983**	$13,608

All derivative instruments are measured at fair value. See Note 9 for additional information.

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$(22,786)**	$ (9,415)	Other regulatory liabilities, current	**$154**	$1,801
	Other regulatory assets, deferred	**(18,197)**	(4,193)	Other regulatory liabilities, deferred	**44**	575
Total energy-related derivative gains (losses)		**$(40,983)**	$(13,608)		**$198**	$2,376

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For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in thousands)				*(in thousands)*	
Interest rate derivatives	**$—**	$(1,405)	$2,934	Interest expense, net of amounts capitalized	**$(933)**	$(974)	$(1,085)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2011, the fair value of derivative liabilities with contingent features was $4.6 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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NOTES (continued)
Gulf Power Company 2011 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2011	**$324,608**	**$32,044**	**$11,691**
June 2011	**399,265**	**67,387**	**33,352**
September 2011	**468,030**	**81,454**	**41,217**
December 2011	**327,909**	**43,839**	**18,745**
March 2010	$356,712	$52,430	$25,300
June 2010	403,171	65,066	32,317
September 2010	483,455	82,896	42,907
December 2010	346,871	46,408	20,987

The Company’s business is influenced by seasonal weather conditions.

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011
Gulf Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in thousands)	**$1,519,812**	$1,590,209	$1,302,229	$1,387,203	$1,259,808
Net Income After Dividends on Preference Stock (in thousands)	**$105,005**	$121,511	$111,233	$98,345	$84,118
Cash Dividends on Common Stock (in thousands)	**$110,000**	$104,300	$89,300	$81,700	$74,100
Return on Average Common Equity (percent)	**9.55**	11.69	12.18	12.66	12.32
Total Assets (in thousands)	**$3,871,881**	$3,584,939	$3,293,607	$2,879,025	$2,498,987
Gross Property Additions (in thousands)	**$337,830**	$285,379	$450,421	$390,744	$239,337
Capitalization (in thousands):					
Common stock equity	**$1,124,948**	$1,075,036	$1,004,292	$822,092	$731,255
Preference stock	**97,998**	97,998	97,998	97,998	97,998
Long-term debt	**1,235,447**	1,114,398	978,914	849,265	740,050
Total (excluding amounts due within one year)	**$2,458,393**	$2,287,432	$2,081,204	$1,769,355	$1,569,303
Capitalization Ratios (percent):					
Common stock equity	**45.8**	47.0	48.3	46.5	46.6
Preference stock	**4.0**	4.3	4.7	5.5	6.2
Long-term debt	**50.2**	48.7	47.0	48.0	47.2
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**378,248**	376,561	374,091	373,595	373,036
Commercial	**53,450**	53,263	53,272	53,548	53,838
Industrial	**273**	272	279	287	298
Other	**565**	562	512	499	491
Total	**432,536**	430,658	428,154	427,929	427,663
Employees (year-end)	**1,424**	1,330	1,365	1,342	1,324

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011 (continued)
Gulf Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in thousands):					
Residential	**$637,352**	$707,196	$588,073	$581,723	$537,668
Commercial	**408,389**	439,468	376,125	369,625	329,651
Industrial	**158,367**	157,591	138,164	165,564	135,179
Other	**4,382**	4,471	4,206	3,854	3,831
Total retail	**1,208,490**	1,308,726	1,106,568	1,120,766	1,006,329
Wholesale — non-affiliates	**133,555**	109,172	94,105	97,065	83,514
Wholesale — affiliates	**111,346**	110,051	32,095	106,989	113,178
Total revenues from sales of electricity	**1,453,391**	1,527,949	1,232,768	1,324,820	1,203,021
Other revenues	**66,421**	62,260	69,461	62,383	56,787
Total	**$1,519,812**	$1,590,209	$1,302,229	$1,387,203	$1,259,808
Kilowatt-Hour Sales (in thousands):					
Residential	**5,304,769**	5,651,274	5,254,491	5,348,642	5,477,111
Commercial	**3,911,399**	3,996,502	3,896,105	3,960,923	3,970,892
Industrial	**1,798,688**	1,685,817	1,727,106	2,210,597	2,048,389
Other	**25,430**	25,602	25,121	23,237	24,496
Total retail	**11,040,286**	11,359,195	10,902,823	11,543,399	11,520,888
Wholesale — non-affiliates	**2,012,986**	1,675,079	1,813,592	1,816,839	2,227,026
Wholesale — affiliates	**2,607,873**	2,436,883	870,470	1,871,158	2,884,440
Total	**15,661,145**	15,471,157	13,586,885	15,231,396	16,632,354
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.01**	12.51	11.19	10.88	9.82
Commercial	**10.44**	11.00	9.65	9.33	8.30
Industrial	**8.80**	9.35	8.00	7.49	6.60
Total retail	**10.95**	11.52	10.15	9.71	8.73
Wholesale	**5.30**	5.33	4.70	5.53	3.85
Total sales	**9.28**	9.88	9.07	8.70	7.23
Residential Average Annual					
Kilowatt-Hour Use Per Customer	**14,028**	15,036	14,049	14,274	14,755
Residential Average Annual					
Revenue Per Customer	**$1,685**	$1,882	$1,572	$1,552	$1,448
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	**2,663**	2,663	2,659	2,659	2,659
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,485**	2,544	2,310	2,360	2,215
Summer	**2,527**	2,519	2,538	2,533	2,626
Annual Load Factor (percent)	**54.5**	56.1	53.8	56.7	55.0
Plant Availability Fossil-Steam (percent)	**84.7**	94.7	89.7	88.6	93.4
Source of Energy Supply (percent):					
Coal	**49.4**	64.6	61.7	77.3	81.8
Gas	**24.0**	17.8	28.0	15.3	13.6
Purchased power —					
From non-affiliates	**22.3**	13.2	2.2	2.6	1.6
From affiliates	**4.3**	4.4	8.1	4.8	3.0
Total	**100.0**	100.0	100.0	100.0	100.0

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MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2011 Annual Report

The management of Mississippi Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

/s/ Edward Day, VI
Edward Day, VI
President and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer

February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the "Company") (a wholly owned subsidiary of The Southern Company) as of December 31, 2011 and 2010, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule of the Company listed in the Index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-377 to II-425) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 24, 2012

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2011 Annual Report

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery.

Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. Hurricane Katrina, the worst natural disaster in the Company's history, hit the Gulf Coast of Mississippi in August 2005, causing substantial damage to the Company's service territory. As of December 31, 2011, the Company had over 8,300 fewer retail customers as compared to pre-storm levels due to obstacles in the rebuilding process as a result of the storm, coupled with the recessionary economy. See Note 1 to the financial statements under "Government Grants" and Note 3 to the financial statements under "Retail Regulatory Matters — Storm Damage Cost Recovery" for additional information.

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi Public Service Commission (PSC). PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.

In June 2010, the Mississippi PSC issued a certification of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of a new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC), which is scheduled to be placed into service in 2014. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

On October 20, 2011, at the completion of the ten year operating lease, the Company purchased the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4) for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 185,000 customers, the Company continues to focus on several key performance indicators. These indicators are used to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in outage minutes per customer (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters — Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to the satisfaction of its customers. Management uses customer satisfaction surveys to evaluate the Company's results. Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The actual Peak Season EFOR performance for 2011 was one of the best in the history of the Company. Net income after dividends on preferred stock is the primary measure of the Company's financial performance.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2011 Annual Report

The Company was slightly below target for 2011 net income after dividends on preferred stock primarily due to lower retail revenue under PEP and higher interest, net of amounts capitalized, partially offset by lower operations and maintenance expenses. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Performance Evaluation Plan" herein for additional information. Recognizing the critical role in the Company's success played by the Company's employees, employee-related measures are a significant management focus. These measures include safety and culture. The 2011 Occupational Safety and Health Administration Incidence Rate was 0.71. The Company is recognized as one of the top in safety performance among all utilities in the Southeastern Electric Exchange. Performance on the Company's culture goals was above target levels for the year.

The Company's 2011 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile overall and in all segments**
Peak Season EFOR	**4.8% or less**	**0.68%**
Net income after dividends on preferred stock	**$98.3 million**	**$94.2 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $94.2 million in 2011 compared to $80.2 million in 2010. The 17.4% increase in 2011 was primarily the result of increases in allowance for funds used during construction (AFUDC) equity related to the construction of the Kemper IGCC which began in June 2010. This increase in net income after dividends on preferred stock was partially offset by decreases in retail base revenues resulting from closer to normal weather in 2011 compared to 2010 and increased depreciation and amortization. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net income after dividends on preferred stock was $80.2 million in 2010 compared to $85.0 million in 2009. The 5.6% decrease in 2010 was primarily the result of decreases in wholesale energy and capacity revenues from customers served outside the Company's service territory and increases in operations and maintenance expenses, depreciation and amortization, and taxes other than income taxes. These decreases in net income after dividends on preferred stock were partially offset by increases in AFUDC equity, revenues attributable to collection of Municipal and Rural Associations (MRA) emissions allowance cost with the Federal Energy Regulatory Commission's (FERC) December 2010 acceptance of the Company's wholesale filing made in October 2010, and territorial base revenues primarily resulting from warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2011 Annual Report

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$1,112.9**	**$(30.2)**	$ (6.3)
Fuel	**490.4**	**(11.4)**	(17.8)
Purchased power	**71.8**	**(11.9)**	(8.3)
Other operations and maintenance	**266.4**	**(1.7)**	21.3
Depreciation and amortization	**80.4**	**3.5**	6.0
Taxes other than income taxes	**70.1**	**0.3**	5.7
Total operating expenses	**979.1**	**(21.2)**	6.9
Operating income	**133.8**	**(9.0)**	(13.2)
Allowance for equity funds used during construction	**24.7**	**20.9**	3.4
Interest income	**1.3**	**1.1**	(0.6)
Interest expense, net of amounts capitalized	**(21.7)**	**0.7**	0.6
Other income (expense), net	**—**	**(3.8)**	1.1
Total other income and (expense)	**4.3**	**18.9**	4.5
Income taxes	**42.2**	**(4.1)**	(3.9)
Net income	**95.9**	**14.0**	(4.8)
Dividends on preferred stock	**1.7**	**—**	—
Net income after dividends on preferred stock	**$ 94.2**	**$ 14.0**	$ (4.8)

Operating Revenues

Details of the Company's operating revenues in 2011 and the prior year were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail — prior year	**$ 797.9**	$ 790.9
Estimated change in —		
Rates and pricing	**0.5**	0.9
Sales growth (decline)	**2.3**	(2.9)
Weather	**(8.9)**	15.0
Fuel and other cost recovery	**0.7**	(6.0)
Retail — current year	**792.5**	797.9
Wholesale revenues —		
Non-affiliates	**273.2**	288.0
Affiliates	**30.4**	41.6
Total wholesale revenues	**303.6**	329.6
Other operating revenues	**16.8**	15.6
Total operating revenues	**$1,112.9**	$1,143.1
Percent change	**(2.6)%**	(0.6)%

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2011 Annual Report

Total retail revenues for 2011 decreased 0.7% compared to 2010 primarily as a result of lower energy sales due to closer to normal weather in 2011 compared to 2010. Total retail revenues for 2010 increased 0.9% compared to 2009 primarily as a result of higher weather-driven energy sales, partially offset by lower fuel revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. The fuel and other cost recovery revenues increased in 2011 compared to 2010 primarily as a result of higher recoverable fuel costs. The fuel and other cost recovery revenues decreased in 2010 compared to 2009 primarily as a result of lower recoverable fuel costs, partially offset by an increase in revenues related to ad valorem taxes. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside the Company's service territory.

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from sales to non-affiliates decreased $14.8 million, or 5.1%, in 2011 compared to 2010 as a result of a $13.4 million decrease in energy revenues, of which $11.4 million was associated with a decrease in kilowatt-hour (KWH) sales and $2.0 million was associated with lower fuel prices, and a $1.4 million decrease in capacity revenues resulting from the expiration of a power supply agreement in December 2010, partially offset by a wholesale MRA base rate increase effective January 2011. Wholesale revenues from sales to non-affiliates decreased $11.4 million, or 3.8%, in 2010 compared to 2009 as a result of a $21.3 million decrease in energy revenues, of which $5.8 million was associated with lower fuel prices and $15.5 million was associated with a decrease in KWH sales, partially offset by a $9.9 million increase in capacity revenues.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC.

Wholesale revenues from sales to affiliated companies decreased 26.9% in 2011 compared to 2010 and decreased 6.6% in 2010 compared to 2009. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues in 2011 increased $1.2 million, or 7.6%, from 2010 primarily due to a $1.8 million increase in transmission revenues. Other operating revenues in 2010 increased $1.0 million, or 6.6%, from 2009 primarily due to a $0.8 million increase in rent from electric property.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2011 Annual Report

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2011 and percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in millions)				
Residential	**2,162**	**(5.8)%**	9.8%	**(0.4)%**	(0.3)%
Commercial	**2,871**	**(1.8)**	2.5	**2.1**	(2.1)
Industrial	**4,586**	**2.7**	3.2	**2.7**	3.2
Other	**39**	**0.3**	(0.7)	**0.3**	(0.7)
Total retail	**9,658**	**(0.7)**	4.4	**1.8**	0.7
Wholesale					
Non-affiliated	**4,010**	**(6.4)**	(7.9)		
Affiliated	**649**	**(16.2)**	(7.8)		
Total wholesale	**4,659**	**(7.9)**	(7.9)		
Total energy sales	**14,317**	**(3.1)**	(0.2)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential energy sales decreased 5.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010 and a slight decline in the number of residential customers in 2011. Residential energy sales increased 9.8% in 2010 compared to 2009 due to warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009.

Commercial energy sales decreased 1.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010. Commercial energy sales increased 2.5% in 2010 compared to 2009 due to warmer weather in the second and third quarters 2010 and colder weather in the first and fourth quarters 2010 compared to the corresponding periods in 2009 and improving economic conditions.

Industrial energy sales increased 2.7% in 2011 compared to 2010 due to increased production for many of the industrial customers resulting from an improving economy as well as expansions of some existing customers. Industrial energy sales increased 3.2% in 2010 compared to 2009 due to a return to more normal production levels for most of the Company's industrial customers from an improving economy.

Wholesale energy sales to non-affiliates decreased 6.4% in 2011 compared to 2010 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from closer to normal weather in 2011 compared to 2010. KWH sales to non-affiliates decreased 7.9% in 2010 compared to 2009 primarily due to fewer short-term opportunity sales related to lower gas prices.

Wholesale sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2011 Annual Report

Wholesale energy sales to affiliates decreased 16.2% in 2011 compared to 2010 primarily due to a decrease in the Company's generation, resulting in less energy available to sell to affiliate companies. Wholesale energy sales to affiliates decreased 7.8% in 2010 compared to 2009 primarily due to an increase in territorial load that was only partially offset by an increase in generation, resulting in less energy available to sell to affiliate companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's electricity generated and purchased were as follows:

	2011	2010	2009
Total generation *(millions of KWHs)*	**12,986**	13,146	12,970
Total purchased power *(millions of KWHs)*	**2,055**	2,330	2,539
Sources of generation *(percent)* –			
Coal	**40**	51	48
Gas	**60**	49	52
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.39**	4.08	4.29
Gas	**3.88**	4.22	4.43
Average cost of fuel, generated *(cents per net KWH)*	**4.10**	4.14	4.36
Average cost of purchased power *(cents per net KWH)*	**3.49**	3.59	3.62

Fuel and purchased power expenses were $562.2 million in 2011, a decrease of $23.3 million, or 4.0%, below the prior year costs. This decrease was primarily due to a $16.5 million decrease related to total KWHs generated and purchased and a $6.8 million decrease in the cost of fuel and purchased power. Fuel and purchased power expenses were $585.5 million in 2010, a decrease of $26.1 million, or 4.3%, below the prior year costs. This decrease was primarily due to a $26.6 million decrease in the cost of fuel and purchased power, partially offset by a $0.5 million increase related to total KWHs generated and purchased.

Fuel expense decreased $11.4 million in 2011 compared to 2010. Approximately $4.8 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $6.6 million decrease in generation from Company-owned facilities. Fuel expense decreased $17.8 million in 2010 compared to 2009. Approximately $25.8 million of the reduction in fuel expenses resulted primarily from lower fuel prices, partially offset by an $8.0 million increase in generation from Company-owned facilities.

Purchased power expense decreased $11.9 million, or 14.2%, in 2011 compared to 2010. The decrease was primarily due to a $2.0 million decrease in the cost of purchased power and a $9.9 million decrease in the amount of energy purchased resulting from higher cost opportunity purchases. Purchased power expense decreased $8.3 million, or 9.0%, in 2010 compared to 2009. The decrease was primarily due to a $0.7 million decrease in the cost of purchased power and a $7.6 million decrease in the amount of energy purchased resulting from higher cost opportunity purchases. Energy purchases vary from year to year depending on demand and the availability and cost of the Company's generating resources. These expenses do not have a significant impact on earnings since the energy purchases are generally offset by energy revenues through the Company's fuel cost recovery clause.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

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Other Operations and Maintenance Expenses

Total other operations and maintenance expenses decreased $1.7 million in 2011 compared to 2010 primarily due to a $4.0 million decrease in rent expense resulting from the expiration of the initial term of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $4.6 million decrease in labor costs. These decreases were partially offset by a $4.2 million increase in generation maintenance expenses for several major outages, a $1.1 million increase in generation-related environmental expenses, and a $2.2 million increase in transmission and distribution expenses related to overhead line maintenance and vegetation maintenance costs. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

Total other operations and maintenance expenses increased $21.3 million in 2010 compared to 2009 primarily due to an $8.5 million increase in generation maintenance expenses for several major planned outages, a $4.2 million increase in transmission and distribution expenses related to substation and overhead line maintenance and vegetation management costs, a $4.6 million increase in administrative and general expenses, and a $5.6 million increase in labor costs.

Depreciation and Amortization

Depreciation and amortization increased $3.5 million in 2011 compared to 2010 primarily due to a $5.2 million increase in depreciation resulting from an increase in plant in service and a $1.5 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4, partially offset by a $2.5 million decrease in amortization resulting from the purchase of Plant Daniel Units 3 and 4 and a $0.7 million decrease in Environmental Compliance Overview (ECO) Plan amortization. Depreciation and amortization increased $6.0 million in 2010 compared to 2009 primarily due to a $2.9 million increase in amortization of environmental costs related to the approved ECO Plan and a $2.7 million increase in depreciation primarily resulting from an increase in plant in service. See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" and "Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $0.3 million in 2011 compared to 2010 primarily as a result of a $0.9 million increase in franchise taxes and a $0.3 million increase in payroll taxes, partially offset by a $0.9 million decrease in ad valorem taxes. Taxes other than income taxes increased $5.7 million in 2010 compared to 2009 primarily as a result of a $5.5 million increase in ad valorem taxes and a $0.2 million increase in payroll taxes.

Allowance for Funds Used During Construction Equity

AFUDC equity increased $20.9 million in 2011 as compared to 2010 and $3.4 million in 2010 as compared to 2009. These increases were primarily due to the construction of the Kemper IGCC which began in June 2010. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Income

Interest income increased $1.1 million in 2011 compared to 2010 primarily due to the deferral of carrying costs on the Kemper IGCC regulatory asset. Interest income decreased $0.6 million in 2010 compared to 2009 primarily due to lower interest income related to a regulatory recovery mechanism for fuel and energy cost hedging.

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Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $0.7 million in 2011 compared to 2010 primarily due to a $5.3 million increase in capitalized AFUDC debt associated with the Kemper IGCC, a $1.9 million decrease in interest expense due to deferred interest on the regulatory assets related to Plant Daniel Units 3 and 4 of $1.4 million and the Kemper IGCC of $0.5 million, and a $1.5 million decrease in interest expense resulting from the amortized premium on the assumed debt related to the purchase of Plant Daniel Units 3 and 4. These decreases were partially offset by a $7.9 million increase in interest expense associated with the issuances of new long-term debt in December 2010, April 2011, September 2011, and October 2011. Interest expense, net of amounts capitalized decreased $0.6 million in 2010 compared to 2009 primarily due to a $2.8 million increase in capitalized AFUDC debt associated with the Kemper IGCC, partially offset by an increase in interest expense associated with the issuances of new long-term debt in September and December 2010.

Other Income (Expense), Net

Other income (expense), net decreased $3.8 million in 2011 compared to 2010 primarily due to a decrease in amounts collected from customers for contributions in aid of construction. Other income (expense), net increased $1.1 million in 2010 compared to 2009 primarily due to a $1.4 million increase in amounts collected from customers for contributions in aid of construction, partially offset by a $0.2 million decrease resulting from mark-to-market losses on energy-related derivative positions.

Income Taxes

Income taxes decreased $4.1 million, or 8.8%, in 2011 compared to 2010 primarily due to an increase in AFUDC equity, which is non-taxable, and an increase in a State of Mississippi manufacturing investment tax credit, partially offset by increased pre-tax income. Income taxes decreased $3.9 million, or 7.8%, in 2010 compared to 2009 primarily due to decreased pre-tax income, a decrease in unrecognized tax benefits, and an increase in AFUDC equity, which is non-taxable, partially offset by a decrease in the federal production activities deduction and a decrease in a State of Mississippi manufacturing investment tax credit.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein, and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Changes in economic conditions impact sales for the Company, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

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Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by the Company. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2011, the Company had invested approximately $249 million in environmental capital retrofit projects to comply with these requirements, with annual totals of $23 million, $2 million, and $22 million for 2011, 2010, and 2009, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $354 million from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$87	$113	$154

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $354 million as described below.

The Company is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $1 billion to $2 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $354 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Company's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $430 million from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to a total of $121 million over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	Up to $30	Up to $100	Up to $300
Proposed water and coal combustion byproducts rules	Up to $1	Up to $30	Up to $90
Total potential incremental environmental compliance investments	**Up to $31**	**Up to $130**	**Up to $390**

The Company's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, the addition of new generating resources, upgrades to the transmission system, and changing fuel sources for certain existing units. The Company's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

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As of December 31, 2011, the Company had total generating capacity of approximately 3,156 MWs, of which 1,450 MWs are coal-fired. As a result of the EPA's final and anticipated rules and regulations, the Company is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of environmental controls, and changing fuel sources for certain units. See "PSC Matters – Environmental Compliance Overview Plan" for information regarding potential construction of a scrubber on Plant Daniel Units 1 and 2.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company spent approximately $132 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. No area within the Company's service area is currently designated as nonattainment under the current standard. In 2008, the EPA adopted a more stringent eight-hour ozone air quality standard, which it began to implement in September 2011. Based on preliminary 2009-2011 ozone data, the EPA is not expected to designate any nonattainment areas within the Company's service territory, based on this revised standard.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Company's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operation costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Company's service territory were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. On April 6, 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts the Greene County, Alabama facility, which the Company jointly owns with Alabama Power. Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves Alabama Power's appeal in its favor, the EPA's rescission will continue to affect the Company's operations with respect to the Greene County, Alabama plant.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and NO_x emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the

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District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the State of Mississippi.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology (BART) to certain sources built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the Company's facilities which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, SO_2 and NO_2 standards, the CSAPR, the CAIR, the CAVR, and the MATS rule on the Company cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, these regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's existing generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs, as described above, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule, and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The Company currently operates two electric generating plants with on-site coal combustion byproducts storage facilities, including both "wet" (ash ponds) and "dry" (landfill) storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Mississippi and Alabama each has its own regulatory parameters. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

While the ultimate outcome of this matter cannot be determined at this time, and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs, as described above, that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in significant additional compliance costs, including significant capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. See Item 1 — BUSINESS — "Rate Matters — Integrated Resource Planning" of the Form 10-K for additional information. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 10 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2011 greenhouse gas emissions on the same basis is approximately 10 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. This includes construction of the Kemper IGCC with approximately 65% carbon capture.

FERC Matters

On November 2, 2011, the Company filed a request with the FERC for revised rates under the wholesale MRA cost-based electric tariff (Tariff). The requested revised rates provide for an increase in annual base wholesale revenues in the amount of approximately $32 million, effective January 1, 2012. In this filing, the Company is also (i) seeking approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) seeking authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) seeking authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules. On December 29, 2011, the Company received an order from the FERC accepting, but suspending for a nominal period, the proposed rate change and establishing a hearing and settlement procedure if an agreement with the wholesale customers could not be reached. On January 20, 2012, the Company reached a settlement agreement with its wholesale customers, which has been executed by all parties. The settlement agreement is currently under review by the FERC staff. The settlement agreement provides that base rates under the Tariff will increase approximately $22.6 million over a 12-month period with revised rates to be effective April 1, 2012. In 2012, the amount of base rate revenues to be received from the agreed upon increase will be approximately $17.0 million. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the construction work in progress (CWIP) recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The settlement agreement states that for future rate matters requiring regulatory accounting approval, the Company may follow for accounting and Tariff rate recovery purposes, the treatment allowed by the Mississippi PSC, if such treatment is not in violation of a FERC policy or rule and if agreed to by the wholesale customers. The Tariff customers specifically agreed to the same regulatory treatment for Tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (a) the accounting for Kemper IGCC-related costs that cannot be capitalized, (b) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (c) the establishment of a regulatory asset for certain potential plant retirement costs. The ultimate outcome of this matter cannot be determined at this time.

PSC Matters

Performance Evaluation Plan

In the 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the Mississippi Public Utilities Staff (MPUS) and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change. In November 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. On January 10, 2011, the MPUS contested the filing. On June 7, 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates. On November 15, 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing. The ultimate outcome of this matter cannot be determined at this time.

In 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007 and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2011, the Company had fully amortized these costs. See Note 3 to the financial statements under "Retail Regulatory Matters — Performance Evaluation Plan" for more information on PEP.

See FINANCIAL CONDITION AND LIQUIDITY — "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information regarding the purchase of Plant Daniel Units 3 and 4. In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4.

On March 15, 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. On May 2, 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On or before March 15, 2012, the Company will submit its annual PEP lookback filing for 2011. The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

On February 14, 2012, the Company submitted its 2012 Environmental Compliance Overview (ECO) Plan notice which proposed a 0.3% increase in annual revenues for the Company. The ultimate outcome of this matter cannot be determined at this time.

On February 14, 2011, the Company submitted its 2011 ECO Plan notice which proposed an immaterial decrease in annual revenues for the Company. In addition, the Company proposed to change the ECO Plan collection period to more appropriately match ECO revenues with ECO expenditures. On April 7, 2011, due to changes in ECO Plan cost projections, the Company submitted a revised 2011 ECO Plan which changed the requested annual revenues to a $0.9 million decrease. On May 5, 2011, the revised ECO Plan filing was approved by the Mississippi PSC with the new rates effective in May 2011.

In February 2010, the Company submitted its 2010 ECO Plan notice which proposed an increase in annual revenues for the Company of approximately $3.9 million. Due to changes in ECO Plan cost projections, in August 2010, the Company submitted a revised 2010 ECO Plan which reduced the requested increase in annual revenues to $1.7 million. In its 2010 ECO Plan filing, the Company proposed to change the true-up provision of the ECO Plan rate schedule to consider actual revenues collected in addition to actual costs. In October 2010, the Mississippi PSC held a public meeting to discuss the 2010 ECO Plan and issued an order approving the revised 2010 ECO Plan with the new rates effective in November 2010. The Company and the MPUS jointly agreed to defer the decision on the change in the true-up provision of the ECO Plan rate schedule. As a result of the change in the collection period requested in the Company's 2011 ECO filing, the Company decided not to pursue the change in the true-up provision.

In July 2010, the Company filed a request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million. The project is scheduled for completion in late 2015. The Company's portion of the cost, if approved by the Mississippi PSC, is expected to be recovered through the ECO Plan. On May 5, 2011, in conjunction with the ECO Plan approval, the Mississippi PSC approved up to $19.5 million (with respect to the Company's ownership portion) in additional spending for 2011 for the scrubber project. As of December 31, 2011, total project expenditures were $45.6 million, with the Company's portion being $22.8 million. During the Mississippi PSC's open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of these matters cannot be determined at this time.

On November 10, 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. On December 6, 2011, an order was granted by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

Certificated New Plant

On April 27, 2011, the Company submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-A (CNP-A), a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. As part of the review of the mechanism, the Mississippi PSC will consider costs to be included as well as the allowed rate of return. CNP-A rate filings are made annually. The first filing was made on November 15, 2011 and requested an 11.66% increase in rates, or approximately $98 million annually, to recover these financing costs. If approved by the Mississippi PSC, CNP-A will remain in place thereafter until the end of the calendar year that the Kemper IGCC is placed into commercial service, which is projected to be 2014.

On August 9, 2011, the Company submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-B (CNP-B) to govern rates effective from the first calendar year after the Kemper IGCC is placed into commercial service through the first seven full calendar years of its operation. Under the proposed CNP-B, the Company's allowed cost of capital would be adjusted based on certain operational performance indicators. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred on November 15, 2011. On January 6, 2012, a revised filing was made with the Mississippi PSC requesting recovery over an 11 month period. The Mississippi PSC approved the retail fuel cost recovery factor on January 11, 2012, with the new rates effective in February 2012. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 2.2% of total 2011 retail revenue. At December 31, 2011, the amount of over recovered retail fuel costs included in the balance sheets was $42.4 million compared to $55.2 million at December 31, 2010. The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2012, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.0% of total 2011 MRA revenue. Effective February 1, 2012, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 4.3% of total 2011 MB revenue. At December 31, 2011, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $14.3 million and $2.2 million compared to $17.5 million and $4.4 million, respectively, at December 31, 2010. In addition, at December 31, 2011, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $1.7 million. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factor will have no significant effect on the Company's revenues or net income, but will decrease annual cash flow.

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On March 31, 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning on April 1, 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. On June 21, 2011, the Company and South Mississippi Electric Power Association (SMEPA) reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA on June 27, 2011. See "Other Matters" herein for additional information.

In October 2010, the Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and energy cost management clause (ECM) for 2010. The 2010 audit was completed in the first quarter 2011 with no audit findings. The 2011 audit of fuel-related expenditures began in the second quarter 2011 and was completed in the fourth quarter 2011 with no audit findings.

Income Tax Matters

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Due to the significant amount of estimated bonus depreciation for 2012 for Southern Company, tax credit utilization will be reduced, thus eliminating the positive cash flow benefit for the Company.

Integrated Coal Gasification Combined Cycle

The Company is constructing the Kemper IGCC that will utilize an IGCC technology with an output capacity of 582 MWs. In May 2010, the Company filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming the Company's application for a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN.

The estimated cost of the plant is $2.4 billion, net of $245.3 million of grants awarded to the project by the Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (CCPI2). The Mississippi PSC's order (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's proposal, and (3) approved financing cost recovery on CWIP balances, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by the Company in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

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The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $245 million. In May 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operation. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operation operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits.

In 2009, the Company received notification from the Internal Revenue Service (IRS) formally certifying that the IRS allocated $133 million of Internal Revenue Code of 1986, as amended (Internal Revenue Code) Section 48A tax credits (Phase I) to the Company. On April 19, 2011, the Company received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to the Company. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through December 31, 2011, the Company received or accrued tax benefits totaling $99.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $77.4 million of these tax credits until after 2012. IRS guidelines allow these unused credits to be carried forward for 20 years expiring at the end of 2031, if not utilized before then.

In 2008, the Company requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida and, later in 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Through December 31, 2011, the Company has received grant funds of $245.3 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for its initial operation.

On March 10, 2011, the Sierra Club filed a lawsuit in the U.S. District Court for the District of Columbia against the DOE regarding the National Environmental Policy Act review process for the Kemper IGCC asking for a preliminary and permanent injunction on the issuance of CCPI2 funds and loan guarantees and a stay to any related construction activities based upon alleged deficiencies in the DOE's environmental impact statement. The Company intervened as a party in this lawsuit on May 18, 2011. On November 18, 2011, the U.S. District Court for the District of Columbia denied the Sierra Club's motion for preliminary injunction in the case and dismissed with prejudice the portion of the Sierra Club's claim relating to loan guarantees. On February 2, 2012, the Sierra Club filed for a voluntary dismissal with prejudice of all remaining claims against the DOE pending in the U.S. District Court for the District of Columbia.

In March 2010, the MDEQ issued the Prevention of Significant Deterioration (PSD) air permit modification for the Kemper IGCC, which modifies the original PSD air permit issued in 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board unanimously affirmed the PSD air permit. On June 30, 2011, the Sierra Club appealed the final PSD air permit issued by the MDEQ to the Chancery Court of Kemper County, Mississippi. The Company has intervened as a party in this appeal.

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club's direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the Mississippi PSC's order authorizing the construction of the Kemper IGCC. On March 1, 2011, the Sierra Club appealed the Chancery Court's decision to the Mississippi Supreme Court.

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In July 2010, the Company and SMEPA entered into an Asset Purchase Agreement whereby SMEPA agreed to purchase a 17.5% undivided ownership interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In December 2010, the Company and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

On March 4, 2011, the Company and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC. On May 19, 2011, the Company and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tenrgys, LLC, entered into a contract pursuant to which Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC.

On June 7, 2011, consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities for the Kemper IGCC. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

On September 9, 2011, the Company filed a request for confirmation of the Kemper IGCC's CPCN with the Mississippi PSC authorizing the acquisition, construction, and operation of approximately 61 miles of CO_2 pipeline infrastructure at an estimated capital cost of $141 million. On January 11, 2012, the Mississippi PSC affirmed the confirmation of the Kemper IGCC's CPCN for the acquisition, construction, and operation of the CO_2 pipeline.

As of December 31, 2011, the Company had spent a total of $943.3 million on the Kemper IGCC, including regulatory filing costs. Of this total, $917.8 million was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $21.4 million was recorded in other regulatory assets, $3.1 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

See PSC Matters — "Certificated New Plant" herein for information on the proposed rate schedules related to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

Other Matters

In 2008, the Company received notice of termination from SMEPA of an approximately 100 MW territorial wholesale market-based contract effective March 31, 2011 which resulted in a decrease in annual base revenues of approximately $12 million. Later in 2008, the Company entered into a 10-year power supply agreement with SMEPA for approximately 152 MWs. This contract was effective April 1, 2011. This contract increased the Company's annual wholesale base revenues by approximately $16.1 million. In September 2010, SMEPA executed a 10-year Network Integration Transmission Service Agreement with Southern Company. Service began on April 1, 2011. The estimated Open Access Transmission Tariff revenue over the life of the contract is approximately $39.3 million with the Company's share being $29.3 million.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

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ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

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Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.3 million or less change in total benefit expense and a $16.3 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2012 through 2014, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012.

Net cash provided from operating activities totaled $231.5 million in 2011 compared to $132.7 million in 2010. The $98.8 million increase in net cash provided from operating activities was primarily due to a $50.6 million decrease in the use of funds related to the Kemper IGCC generation construction screening costs incurred during the first five months of 2010. The Mississippi PSC issued an order in June 2010 approving the Kemper IGCC. Pension, postretirement, and other employee benefits increased by $38.1 million primarily due to a cash payment made in 2010 to fund the qualified pension plan, other accounts payable increased by $36.8 million, and deferred income taxes increased by $34.2 million primarily related to a long-term service agreement (LTSA), bonus depreciation, and fuel cost recovery. Prepaid income taxes increased $30.0 million primarily due to tax refunds related to 2010 investment tax credits received in 2011. These increases in cash provided from operating activities were partially offset by a $45.0 million decrease in over recovered regulatory clause revenues related to lower fuel rates in 2011 and 2010 and a decrease in fossil fuel stock of $42.9 million primarily due to increases in coal and coal in transit. Net cash provided from operating activities totaled $132.7 million in 2010 compared to $170.6 million for 2009. The $38.0 million decrease in net cash provided from operating activities was primarily due to a $42.9 million cash payment to fund the qualified pension plan, an increase in spending related to the Kemper IGCC generation construction screening costs of $19.9 million, and a decrease in cash received related to lower fuel rates effective in the first quarter 2010. These decreases in cash were partially offset by an increase in deferred income taxes of $77.4 million primarily related to a LTSA, bonus depreciation, and an increase in investment tax credits of $22.2 million related to the Kemper IGCC.

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Net cash used for investing activities totaled $682.7 million for 2011 compared to $254.4 million for 2010. The $428.3 million increase was primarily due to an increase in property additions of $717.2 million primarily related to the Kemper IGCC and an increase in plant acquisition of $84.8 million due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4. These increases in cash used for investing activities were partially offset by a construction payable increase of $63.3 million, a $100.0 million change in restricted cash associated with the second series revenue bonds issued in December 2010, and an increase of $208.8 million in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants. Net cash used for investing activities totaled $254.4 million for 2010 compared to $119.4 million for 2009. The $135.0 million increase was primarily due to an increase in property additions of $145.0 million primarily related to the Kemper IGCC and an increase in investment in restricted cash of $50.0 million, partially offset by capital grant proceeds of $23.7 million related to CCPI2 and the Smart Grid Investment grant and $33.8 million in construction payables. See FUTURE EARNINGS POTENTIAL — "Integrated Coal Gasification Combined Cycle" herein for additional information.

Net cash provided from financing activities totaled $502.0 million in 2011 compared to $217.5 million in 2010. The $284.5 million increase in net cash provided from financing activities was primarily due to a $234.1 million increase in capital contributions from Southern Company, a $190.0 million increase in long-term debt, and a $130 million redemption of long-term debt. Net cash provided from financing activities totaled $217.5 million in 2010 compared to net cash used for financing activities of $8.6 million in 2009. The $226.1 million increase was primarily due to a $100.0 million increase in long-term debt at December 31, 2010, a $60.6 million increase in capital contributions from Southern Company, and a $40.0 million redemption of long-term debt in the third quarter 2009.

Significant changes in the balance sheet as of December 31, 2011 compared to 2010 include an increase in total property, plant, and equipment of $1.1 billion primarily due to the increase in construction work in progress related to the Kemper IGCC and an increase in plant in service related to the purchase of Plant Daniel Units 3 and 4. Other accounts payable increased $109.0 million primarily due to increases in construction projects. Long-term debt increased $641.6 million primarily due to the assumption of $270.0 million taxable revenue bonds in October 2011 and the issuance of $300.0 million of senior notes in October 2011. Accumulated deferred investment tax credits increased $76.1 million primarily related to the Kemper IGCC. Common stockholder's equity increased $311.8 million primarily due to the increase in paid-in capital due to $300.0 million in capital contributions from Southern Company in 2011.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, decreased from 59.8% in 2010 to 48.0% at December 31, 2011.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. In 2011, the Company received $300 million in capital contributions from Southern Company. See "Capital Requirements and Contractual Obligations" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. The amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

The Company has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. The Company is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees to the Company. Through December 31, 2011, the Company has received $245.3 million in DOE CCPI2 grant funds that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC.

Investment tax credits related to the Kemper IGCC of $77.4 million are not expected to be utilized until after 2012, which could result in additional financing needs. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

At December 31, 2011, the Company had approximately $211.6 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

Expires [(a)]				Executable Term-Loans	
2012	2014	Total	Unused	One Year	Two Years
		(in millions)			
$131	$165	$296	$296	$25	$41

(a) No credit arrangements expire in 2013, 2015, or 2016.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross-default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. The Company is currently in compliance with all such covenants.

These credit arrangements provide liquidity support to the Company's variable rate tax-exempt pollution control revenue bonds and commercial paper borrowings. At December 31, 2011, the Company had $40.1 million of outstanding pollution control revenue bonds requiring liquidity support.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$—	—%	$ 7	0.21%	$70
December 31, 2010:					
Commercial paper	$—	—%	$12	0.28%	$63

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

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Financing Activities

In February 2011, the Company redeemed a $50 million series of revenue bonds issued in December 2010.

In March 2011, the Company's $80 million long-term bank note with a variable interest rate based on one-month London Interbank Offered Rate (LIBOR) matured.

In April 2011, the Company entered into a one-year $75 million aggregate principal amount long-term floating rate bank loan with a variable interest rate based on one-month LIBOR. The proceeds of this loan were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

In September 2011, the Company entered into a one-year $40 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The proceeds were used to repay outstanding short-term debt and for general corporate purposes, including the Company's continuous construction program. In addition, the Company entered into a one-year extension of a $125 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR.

In September 2011, the Company entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to anticipated debt issuances. The notional amount of the swaps totaled $600 million. The Company settled $300 million of the interest rate swaps in October 2011; $150 million related to its Series 2011A 2.35% Senior Note issuance at a gain of approximately $1.4 million which will be amortized to interest expense, in earnings, over five years and $150 million related to its Series 2011B 4.75% Senior Note issuance at a loss of approximately $0.5 million which will be amortized to interest expense, in earnings, over 10 years.

In October 2011, the Company issued $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016 and $150 million aggregate principal amount of Series 2011B 4.75% Senior Notes due October 15, 2041. The net proceeds were used by the Company to pay amounts in connection with the purchase of Plant Daniel Units 3 and 4 as described herein under "Purchase of the Plant Daniel Combined Cycle Generating Units," and for general corporate purposes, including the Company's continuous construction program.

In October 2011, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds have been recorded on the financial statements at the fair value of the debt on the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began an initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. The Company was required to provide notice of its intent to either renew the lease or purchase Plant Daniel Units 3 and 4 by July 22, 2011. On July 20, 2011, the Company provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4. The Company's right to purchase Plant Daniel Units 3 and 4 was approved by the Mississippi PSC in its order dated January 7, 1998, as amended on February 19, 1999, which granted the Company a CPCN for Plant Daniel Units 3 and 4.

On October 20, 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. See Note 1 to the financial statements under "Purchase of the Plant Daniel Combined Cycle Generating Units" for additional information regarding the debt valuation. Accordingly, Plant Daniel Units 3 and 4 are reflected in the Company's financial statements at $430.9 million.

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In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. On November 2, 2011, the Company filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The ultimate outcome of this matter cannot be determined at this time.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At December 31, 2011, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $330 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $280 million of outstanding variable rate long-term debt at December 31, 2011 was 0.63%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $2.8 million at December 31, 2011. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market. At December 31, 2011, exposure from these activities was not material to the Company's financial statements.

In addition, per the guidelines of the Mississippi PSC, the Company has implemented a fuel-hedging program. At December 31, 2011, exposure from these activities was not material to the Company's financial statements.

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The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$(43,770)**	$(41,734)
Contracts realized or settled	**32,381**	32,853
Current period changes [(a)]	**(39,601)**	(34,889)
Contracts outstanding at the end of the period, assets (liabilities), net	**$(50,990)**	$(43,770)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was a decrease of $7.2 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, the Company had a net hedge volume of 31.0 million mmBtu with a weighted average swap contract cost of approximately $1.98 per mmBtu above market prices, and a net hedge volume of 24.0 million mmBtu at December 31, 2010 with a weighted average swap contract cost of approximately $1.92 per mmBtu above market prices. The majority of the costs associated with natural gas hedges are recovered through the Company's ECM clause.

At December 31, 2011 and 2010, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented. The pre-tax gains/(losses) reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2012.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in thousands)			
Level 1	**$ —**	$ —	$ —	$ —
Level 2	50,990	36,330	14,371	289
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$50,990	$36,330	$14,371	$289

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Included in the estimated base level capital investment amounts are expenditures related to the Kemper IGCC of $1.3 billion, $124 million, and $74 million in 2012, 2013, and 2014, respectively, which are net of SMEPA's 17.5% expected ownership share of the Kemper IGCC of approximately $466 million and $16 million in 2013 and 2014, respectively. These estimated base level capital investment amounts also include capital expenditures covered under LTSAs. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as described below. Although its analyses are preliminary, the Company estimates that the aggregate capital costs for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $1 billion to $2 billion through 2021 based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $354 million that is also included in the Company's 2012 through 2014 base level capital investment described herein in anticipation of these rules. The Company's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$1,409	$250	$ 198
Existing environmental statutes and regulations	87	113	154
Total construction program base level capital investment	**$1,496**	**$363**	**$ 352**
Potential incremental environmental compliance investments:			
MATS rule	Up to $30	Up to $100	Up to $300
Proposed water and coal combustion byproducts rules	Up to $1	Up to $30	Up to $90
Total potential incremental environmental compliance investments	**Up to $31**	**Up to $130**	**Up to $390**

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing [d]	Total
			(in thousands)			
Long-term debt [a] —						
Principal	$ 240,000	$ 50,000	$150,000	$ 832,695	$ —	$1,272,695
Interest	53,580	100,680	97,680	467,682	—	719,622
Preferred stock dividends [b]	1,733	3,465	3,465	—	—	8,663
Energy-related derivative obligations [c]	36,455	14,372	325	—	—	51,152
Foreign currency derivative obligations [c]	2,464	46	—	—	—	2,510
Interest rate derivative obligations [c]	15,208	—	—	—	—	15,208
Unrecognized tax benefits and interest [d]	3,349	—	—	—	2,295	5,644
Operating leases [e]	11,870	20,984	2,087	523	—	35,464
Capital leases [f]	633	—	—	—	—	633
Purchase commitments [g] —						
Capital [h]	1,495,583	683,013	—	—	—	2,178,596
Coal	267,075	58,205	1,920	35,520	—	362,720
Natural gas [i]	159,394	265,426	181,486	146,169	—	752,475
Long-term service agreements [j]	14,123	29,287	30,212	30,264	—	103,886
Pension and other postretirement benefits plans [k]	5,232	11,288	—	—	—	16,520
Total	$2,306,699	$1,236,766	$467,175	$1,512,853	$2,295	$5,525,788

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2012, as reflected in the statements of capitalization. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 10 to the financial statements.

(d) The timing related to the realization of $2.3 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) The capital lease of $6.4 million is being amortized over a five-year period ending in 2012.

(g) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2011, 2010, and 2009 were $266 million, $268 million, and $247 million, respectively.

(h) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Company's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $31 million, up to $130 million, and up to $390 million for 2012, 2013, and 2014, respectively. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. Estimates include the sale of 17.5% of the Kemper IGCC to SMEPA. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(i) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(j) Long-term service agreements include price escalation based on inflation indices.

(k) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, storm damage cost recovery and repairs, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, the pending EPA civil action, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals, potential DOE loan guarantees, the SMEPA purchase decision, and utilization of investment tax credits;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010, and 2009
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	2011	2010	2009
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 792,463**	$ 797,912	$ 790,950
Wholesale revenues, non-affiliates	**273,178**	287,917	299,268
Wholesale revenues, affiliates	**30,417**	41,614	44,546
Other revenues	**16,819**	15,625	14,657
Total operating revenues	**1,112,877**	1,143,068	1,149,421
Operating Expenses:			
Fuel	**490,415**	501,830	519,687
Purchased power, non-affiliates	**6,239**	8,426	8,831
Purchased power, affiliates	**65,574**	75,230	83,104
Other operations and maintenance	**266,395**	268,063	246,758
Depreciation and amortization	**80,337**	76,891	70,916
Taxes other than income taxes	**70,127**	69,810	64,068
Total operating expenses	**979,087**	1,000,250	993,364
Operating Income	**133,790**	142,818	156,057
Other Income and (Expense):			
Allowance for equity funds used during construction	**24,707**	3,795	387
Interest income	**1,347**	215	804
Interest expense, net of amounts capitalized	**(21,691)**	(22,341)	(22,940)
Other income (expense), net	**(45)**	3,738	2,606
Total other income and (expense)	**4,318**	(14,593)	(19,143)
Earnings Before Income Taxes	**138,108**	128,225	136,914
Income taxes	**42,193**	46,275	50,214
Net Income	**95,915**	81,950	86,700
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income After Dividends on Preferred Stock	**$ 94,182**	$ 80,217	$ 84,967

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Mississippi Power Company 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Net Income After Dividends on Preferred Stock	**$ 94,182**	$ 80,217	$ 84,967
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(5,494), $1, and $-, respectively	**(8,870)**	2	—
Reclassification adjustment for amounts included in net income, $(18), $-, and $-, respectively	**(29)**	—	—
Total other comprehensive income (loss)	**(8,899)**	2	—
Comprehensive Income	**$ 85,283**	$ 80,219	$ 84,967

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
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	2011	2010	2009
		(in thousands)	
Operating Activities:			
Net income	**$ 95,915**	$ 81,950	$ 86,700
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**83,787**	82,294	78,914
Deferred income taxes	**71,764**	37,557	(39,849)
Investment tax credits received	**—**	22,173	—
Allowance for equity funds used during construction	**(24,707)**	(3,795)	(387)
Pension, postretirement, and other employee benefits	**3,169**	(34,911)	7,077
Hedge settlements	**848**	—	—
Stock based compensation expense	**1,548**	1,186	886
Generation construction screening costs	**—**	(50,554)	(30,638)
Other, net	**(8,151)**	(3,404)	(3,229)
Changes in certain current assets and liabilities —			
-Receivables	**5,864**	(8,185)	9,677
-Under recovered regulatory clause revenues	**—**	—	54,994
-Fossil fuel stock	**(27,933)**	14,997	(41,699)
-Materials and supplies	**(2,116)**	(879)	(649)
-Prepaid income taxes	**12,907**	(17,075)	1,061
-Other current assets	**1,606**	(4,633)	2,065
-Other accounts payable	**24,143**	(12,630)	(7,590)
-Accrued taxes	**1,209**	(4,268)	8,800
-Accrued compensation	**(187)**	2,291	(6,819)
-Over recovered regulatory clause revenues	**(16,544)**	28,450	48,596
-Other current liabilities	**8,373**	2,137	2,732
Net cash provided from operating activities	**231,495**	132,701	170,642
Investing Activities:			
Property additions	**(964,233)**	(247,005)	(101,995)
Plant acquisition	**(84,803)**	—	—
Investment in restricted cash	**—**	(50,000)	—
Distribution of restricted cash	**50,000**	—	—
Cost of removal net of salvage	**(7,432)**	(9,240)	(9,352)
Construction payables	**97,079**	33,767	(5,091)
Capital grant proceeds	**232,442**	23,657	—
Other investing activities	**(5,736)**	(5,587)	(2,971)
Net cash used for investing activities	**(682,683)**	(254,408)	(119,409)
Financing Activities:			
Decrease in notes payable, net	**—**	—	(26,293)
Proceeds —			
Capital contributions from parent company	**299,305**	65,215	4,567
Senior notes issuances	**300,000**	—	125,000
Other long-term debt issuances	**115,000**	225,000	—
Redemptions —			
Capital leases	**(1,437)**	(1,330)	—
Senior notes	**—**	—	(40,000)
Other long-term debt	**(130,000)**	—	—
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,733)
Payment of common stock dividends	**(75,500)**	(68,600)	(68,500)
Other financing activities	**(3,641)**	(1,091)	(1,662)
Net cash provided from (used for) financing activities	**501,994**	217,461	(8,621)
Net Change in Cash and Cash Equivalents	**50,806**	95,754	42,612
Cash and Cash Equivalents at Beginning of Year	**160,779**	65,025	22,413
Cash and Cash Equivalents at End of Year	**$ 211,585**	$ 160,779	$ 65,025

Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $10,065, $2,903 and $117 capitalized, respectively)	**$ 14,814**	$ 19,518	$ 19,832
Income taxes (net of refunds)	**(41,024)**	7,546	77,206
Noncash transactions — accrued property additions at year-end	**135,902**	37,736	3,689
Assumption of debt due to plant acquisition	**346,051**	—	—

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
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Assets	**2011**	2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 211,585**	$ 160,779
Restricted cash	**—**	50,000
Receivables —		
Customer accounts receivable	**32,551**	37,532
Unbilled revenues	**27,239**	31,010
Other accounts and notes receivable	**7,080**	11,220
Affiliated companies	**23,078**	17,837
Accumulated provision for uncollectible accounts	**(547)**	(638)
Fossil fuel stock, at average cost	**140,173**	112,240
Materials and supplies, at average cost	**30,787**	28,671
Other regulatory assets, current	**69,201**	63,896
Prepaid income taxes	**37,793**	59,596
Other current assets	**8,881**	19,057
Total current assets	**587,821**	591,200
Property, Plant, and Equipment:		
In service	**2,902,240**	2,392,477
Less accumulated provision for depreciation	**1,019,251**	971,559
Plant in service, net of depreciation	**1,882,989**	1,420,918
Construction work in progress	**955,135**	274,585
Total property, plant, and equipment	**2,838,124**	1,695,503
Other Property and Investments	**6,520**	5,900
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**25,009**	18,065
Other regulatory assets, deferred	**185,694**	132,420
Other deferred charges and assets	**28,674**	33,233
Total deferred charges and other assets	**239,377**	183,718
Total Assets	**$3,671,842**	$2,476,321

The accompanying notes are an integral part of these financial statements.

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BALANCE SHEETS
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Liabilities and Stockholder's Equity	**2011**	2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 240,633**	$ 256,437
Accounts payable —		
Affiliated	**62,650**	51,887
Other	**168,309**	59,295
Customer deposits	**13,658**	12,543
Accrued taxes —		
Accrued income taxes	**3,813**	4,356
Other accrued taxes	**53,825**	51,709
Accrued interest	**12,750**	5,933
Accrued compensation	**15,889**	16,076
Other regulatory liabilities, current	**5,779**	6,177
Over recovered regulatory clause liabilities	**60,502**	77,046
Liabilities from risk management activities	**54,127**	27,525
Other current liabilities	**17,533**	20,115
Total current liabilities	**709,468**	589,099
Long-Term Debt (See accompanying statements)	**1,103,596**	462,032
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**270,397**	281,967
Deferred credits related to income taxes	**11,058**	11,792
Accumulated deferred investment tax credits	**109,761**	33,678
Employee benefit obligations	**161,065**	113,964
Other cost of removal obligations	**126,424**	111,614
Other regulatory liabilities, deferred	**60,848**	58,814
Other deferred credits and liabilities	**37,228**	43,213
Total deferred credits and other liabilities	**776,781**	655,042
Total Liabilities	**2,589,845**	1,706,173
Cumulative Redeemable Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**1,049,217**	737,368
Total Liabilities and Stockholder's Equity	**$3,671,842**	$2,476,321
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF CAPITALIZATION
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	2011	2010	2011	2010
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
6.00% due 2013	**50,000**	50,000		
2.35% due 2016	**150,000**	—		
2.25% to 5.625% due 2017-2041	**480,000**	330,000		
Adjustable rates (0.56% to 0.71% at 1/1/11) due 2011	**—**	205,000		
Adjustable rates (0.60% to 0.85% at 1/1/12) due 2012	**240,000**	—		
Adjustable rates (0.44% at 1/1/11) due 2040	**—**	50,000		
Total long-term notes payable	**920,000**	635,000		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.08% to 0.16% at 1/1/12) due 2020-2028	**40,070**	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	**270,000**	—		
Total other long-term debt	**352,695**	82,695		
Capitalized lease obligations	**633**	2,070		
Unamortized debt premium (related to plant acquisition)	**74,551**	—		
Unamortized debt discount	**(3,650)**	(1,296)		
Total long-term debt (annual interest requirement — $53.6 million)	**1,344,229**	718,469		
Less amount due within one year	**240,633**	256,437		
Long-term debt excluding amount due within one year	**1,103,596**	462,032	**50.5%**	37.5%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	**32,780**	32,780	**1.5**	2.7
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**694,855**	392,790		
Retained earnings	**325,568**	306,885		
Accumulated other comprehensive income (loss)	**(8,897)**	2		
Total common stockholder's equity	**1,049,217**	737,368	**48.0**	59.8
Total Capitalization	**$2,185,593**	$1,232,180	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)		
Balance at December 31, 2008	1,121	$37,691	$319,958	$278,802	$ —	$ 636,451
Net income after dividends on preferred stock	—	—	—	84,967	—	84,967
Capital contributions from parent company	—	—	5,604	—	—	5,604
Cash dividends on common stock	—	—	—	(68,500)	—	(68,500)
Balance at December 31, 2009	1,121	37,691	325,562	295,269	—	658,522
Net income after dividends on preferred stock	—	—	—	80,217	—	80,217
Capital contributions from parent company	—	—	67,228	—	—	67,228
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(68,600)	—	(68,600)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2010	**1,121**	**37,691**	**392,790**	**306,885**	**2**	**737,368**
Net income after dividends on preferred stock	**—**	**—**	**—**	**94,182**	**—**	**94,182**
Capital contributions from parent company	**—**	**—**	**302,065**	**—**	**—**	**302,065**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(8,899)**	**(8,899)**
Cash dividends on common stock	**—**	**—**	**—**	**(75,500)**	**—**	**(75,500)**
Other	**—**	**—**	**—**	**1**	**—**	**1**
Balance at December 31, 2011	**1,121**	**$37,691**	**$694,855**	**$325,568**	**$(8,897)**	**$1,049,217**

The accompanying notes are an integral part of these financial statements.

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NOTES TO FINANCIAL STATEMENTS
Mississippi Power Company 2011 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies — Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and the Company — are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment, but is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Mississippi Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $185.5 million, $125.1 million, and $84.0 million during 2011, 2010, and 2009, respectively. The increase in 2011 SCS costs is primarily due to the construction of the new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC) and large environmental projects. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of all associated expenditures and costs, which totaled $12.2 million, $11.2 million, and $10.2 million in 2011, 2010, and 2009, respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $23.3 million, $25.0 million, and $20.9 million in 2011, 2010, and 2009, respectively. See Note 4 for additional information.

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The traditional operating companies, including the Company, and Southern Power jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2011	2010	Note
	(in thousands)		
Hurricane Katrina	**$ —**	$ (143)	(a)
Retiree benefit plans	**130,678**	86,748	(b,k)
Property damage	**(64,748)**	(61,171)	(m)
Deferred income tax charges	**21,000**	13,654	(d)
Property tax	**18,484**	18,649	(e)
Transmission & distribution deferral	**—**	2,367	(f)
Vacation pay	**9,128**	9,143	(g,k)
Loss on reacquired debt	**7,171**	7,775	(h)
Loss on redeemed preferred stock	**—**	57	(i)
Loss on rail cars	**—**	8	(h)
Plant Daniel Units 3 and 4 regulatory assets	**3,945**	—	(o)
Other regulatory assets	**132**	—	(c)
Fuel-hedging (realized and unrealized) losses	**54,103**	48,729	(j,k)
Asset retirement obligations	**9,057**	9,302	(d)
Deferred income tax credits	**(12,081)**	(13,189)	(d)
Other cost of removal obligations	**(126,424)**	(111,614)	(d)
Fuel-hedging (realized and unrealized) gains	**(162)**	(2,067)	(j,k)
Kemper IGCC regulatory assets	**20,684**	12,295	(l)
Other liabilities	**(693)**	(81)	(c)
Deferred income tax charges — Medicare subsidy	**5,521**	5,521	(n)
Total assets (liabilities), net	**$ 75,795**	$ 25,983	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) For additional information, see Note 3 under "Retail Regulatory Matters — Storm Damage Cost Recovery."

(b) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(c) Recorded and recovered as approved by the Mississippi PSC.

(d) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(e) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.

(f) Amortized over a four-year period ending December 2011.

(g) Recorded as earned by employees and recovered as paid, generally within one year.

(h) Recovered over the remaining life of the original issue/lease or, if refinanced, over the life of the new issue/lease, which may range up to 50 years.

(i) Amortized over a seven-year period ending in April 2011.

(j) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, costs are recovered through the Energy Cost Management clause (ECM).

(k) Not earning a return as offset in rate base by a corresponding asset or liability.

(l) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle."

(m) For additional information, see Note 1 under "Provision for Property Damage" and Note 3 under "Retail Regulatory Matters — System Restoration Rider."

(n) Recovered and amortized over a 10-year period beginning in 2012, as approved by the Mississippi PSC for the retail portion and a five-year period for the wholesale portion, as approved by FERC. See Note 5 for additional information.

(o) Recovered and amortized over a 10-year period ending October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term. See Note 3 under "Retail Regulatory Matters — Performance Evaluation Plan" for additional information.

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In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated other comprehensive income (OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2008, the Company requested that the Department of Energy (DOE) transfer the remaining funds previously granted under the Clean Coal Power Initiative Round 2 (CCPI2) from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida. In August 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper IGCC through the CCPI2 funds. Through December 31, 2011, the Company has received grant funds of $245.3 million, used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25 million is expected to be received for its initial operation.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery factor annually.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel costs also include gains and/or losses from fuel hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

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Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects over $1 million where recovery of construction work in progress is not allowed in rates.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2011	2010
	(in thousands)	
Generation	**$1,362,567**	$ 990,151
Transmission	**497,202**	464,716
Distribution	**784,655**	765,578
General	**176,408**	172,032
Plant acquisition adjustment	**81,408**	—
Total plant in service	**$2,902,240**	$2,392,477

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense except for the cost of maintenance of coal cars and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of an operating lease agreement for combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4). On July 20, 2011, the Company provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4. The Company's right to purchase Plant Daniel Units 3 and 4 was approved by the Mississippi PSC in its order dated January 7, 1998, as amended on February 19, 1999, which granted the Company a Certificate of Public Convenience and Necessity (CPCN) for Plant Daniel Units 3 and 4.

On October 20, 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 are reflected in the Company's financial statements as follows:

Assumption of debt obligations	$270,000
Fair value adjustment at date of purchase	76,051
Total debt	346,051
Cash payment for the purchase	84,803
Total value of Plant Daniel Units 3 and 4	$430,854

See Note 3 under "Retail Regulatory Matters — Performance Evaluation Plan" for additional information.

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Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.9% in 2011, 3.4% in 2010, and 3.3% in 2009. Depreciation studies are conducted periodically to update the composite rates. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities. In 2009, the Company filed a depreciation study as of December 31, 2008 with the Mississippi PSC and the FERC. The FERC accepted this study in 2009. In April 2010, the Mississippi PSC issued an order approving the depreciation rates effective January 1, 2010. This change did not have a material impact on the financial statements.

The Company, in compliance with FERC guidance, classified $81.4 million as a plant acquisition adjustment on the purchase of Plant Daniel Units 3 and 4. This includes $76.1 million recorded in conjunction with the premium on long-term debt and will be amortized over 10 years beginning October 2011. See "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

On January 11, 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10-year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

In 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007 and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2011, the Company had fully amortized these costs.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, deep injection wells, water wells, substation removal, generator removal, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

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Details of the asset retirement obligations included in the balance sheets are as follows:

	2011	2010
	(in thousands)	
Balance at beginning of year	**$18,601**	$17,431
Liabilities incurred	**137**	(1)
Liabilities settled	**(644)**	155
Accretion	**1,054**	1,016
Cash flow revisions	**—**	—
Balance at end of year	**$19,148**	$18,601

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.06%, 7.33%, and 7.92% for the years ended December 31, 2011, 2010, and 2009, respectively. The AFUDC rate is applied to construction work in progress based on jurisdictional regulatory recovery mechanisms. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 31.60%, 6.97%, and 0.5% for 2011, 2010, and 2009, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the asset and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. In January 2009, the Mississippi PSC approved the System Restoration Rider (SRR) stipulation between the Company and the Mississippi Public Utilities Staff (MPUS). In accordance with the stipulation, every three years the Mississippi PSC, MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. Each year the Company will set rates to collect the approved SRR revenues. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In 2011, 2010, and 2009, the Company made retail accruals of $3.8 million, $3.1 million, and $3.7 million, respectively, per the annual SRR rate filings. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. See Note 3 under “Retail Regulatory Matters — System Restoration Rider” for additional information. The Company accrued $0.3 million annually in 2011, 2010 and in 2009 for the wholesale jurisdiction.

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Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Restricted Cash

In December 2010, the Company incurred obligations relating to the issuance of $50 million of revenue bonds. The proceeds of this issuance are presented as restricted cash on the balance sheet at December 31, 2010. These bonds were redeemed on February 8, 2011.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, and emissions allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates. The retail rate is approved by the Mississippi PSC while the wholesale rates are filed with the FERC. Emissions allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel hedging program as discussed below. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Foreign currency exchange rate hedges are designated as fair value hedges. Settled hedges are booked as construction work in progress (CWIP). Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging program instruments relating to the Kemper IGCC to a regulatory asset. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2011.

The Mississippi PSC has approved the Company's request to implement an ECM which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

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Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income after dividends on preferred stock, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this accounting guidance did not result in the Company consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. For the years ended 2011 and 2010, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2012, other postretirement trust contributions are expected to be less than $1 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.51%	5.92%
Other postretirement benefit plans	**4.87**	5.39	5.83
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.53**	7.65	7.62

* Net of estimated investment management expenses of 30 basis points.

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2011 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2011 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$6,062	$(5,156)
Service and interest costs	365	(310)

Pension Plans

The total accumulated benefit obligation for the pension plans was $339 million at December 31, 2011 and $307 million at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$330,315**	$309,179
Service cost	**8,838**	8,300
Interest cost	**17,827**	17,916
Benefits paid	**(14,587)**	(12,206)
Plan amendments	**—**	48
Actuarial loss (gain)	**27,287**	7,078
Balance at end of year	**369,680**	330,315
Change in plan assets		
Fair value of plan assets at beginning of year	**283,698**	218,015
Actual return (loss) on plan assets	**10,805**	33,780
Employer contributions	**2,184**	44,109
Benefits paid	**(14,587)**	(12,206)
Fair value of plan assets at end of year	**282,100**	283,698
Accrued liability	**$ (87,580)**	$ (46,617)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $344 million and $26 million, respectively. All pension plan assets are related to the qualified pension plan.

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Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in thousands)	
Other regulatory assets, deferred	**$117,354**	$ 78,130
Other current liabilities	**(1,652)**	(1,516)
Employee benefit obligations	**(85,928)**	(45,101)

Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2012.

	2011	2010	Estimated Amortization in 2012
		(in thousands)	
Prior service cost	**$ 6,570**	$ 7,879	**$1,309**
Net (gain) loss	**110,784**	70,251	**4,100**
Other regulatory assets, deferred	**$117,354**	$78,130	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2009	$ 85,357
Net (gain) loss	(5,250)
Change in prior service costs	48
Reclassification adjustments:	
Amortization of prior service costs	(1,391)
Amortization of net gain (loss)	(634)
Total reclassification adjustments	(2,025)
Total change	(7,227)
Balance at December 31, 2010	$ 78,130
Net (gain) loss	**41,647**
Change in prior service costs	**—**
Reclassification adjustments:	
Amortization of prior service costs	**(1,309)**
Amortization of net gain (loss)	**(1,114)**
Total reclassification adjustments	**(2,423)**
Total change	**39,224**
Balance at December 31, 2011	**$117,354**

Components of net periodic pension cost were as follows:

	2011	2010	2009
		(in thousands)	
Service cost	**$ 8,838**	$ 8,300	$ 6,792
Interest cost	**17,827**	17,916	17,577
Expected return on plan assets	**(25,166)**	(21,451)	(21,065)
Recognized net (gain) loss	**1,114**	634	539
Net amortization	**1,309**	1,391	1,578
Net periodic pension cost	**$ 3,922**	$ 6,790	$ 5,421

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Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2012	$ 15,125
2013	15,892
2014	16,722
2015	17,528
2016	18,457
2017 to 2021	109,185

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 81,688**	$ 83,774
Service cost	**1,012**	1,305
Interest cost	**4,292**	4,763
Benefits paid	**(4,094)**	(4,245)
Actuarial loss (gain)	**4,073**	(2,511)
Plan amendments	**—**	(1,824)
Retiree drug subsidy	**476**	426
Balance at end of year	**87,447**	81,688
Change in plan assets		
Fair value of plan assets at beginning of year	**20,955**	20,292
Actual return (loss) on plan assets	**720**	2,297
Employer contributions	**2,477**	2,185
Benefits paid	**(3,618)**	(3,819)
Fair value of plan assets at end of year	**20,534**	20,955
Accrued liability	**$(66,913)**	$(60,733)

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in thousands)	
Other regulatory assets, deferred	**$ 13,324**	$ 8,618
Employee benefit obligations	**(66,913)**	(60,733)

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Presented below are the amounts included in regulatory assets at December 31, 2011 and 2010 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2012.

	2011	2010	**Estimated Amortization in 2012**
		(in thousands)	
Prior service cost	**$(2,686)**	$(2,873)	**$(188)**
Net (gain) loss	**15,839**	11,092	**487**
Transition obligation	**171**	399	**171**
Other regulatory assets, deferred	**$13,324**	$ 8,618	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2011 and 2010 are presented in the following table:

	Regulatory Assets
	(in thousands)
Balance at December 31, 2009	$14,332
Net (gain) loss	(3,316)
Change in prior service costs/transition obligation	(1,824)
Reclassification adjustments:	
Amortization of transition obligation	(228)
Amortization of prior service costs	57
Amortization of net gain (loss)	(403)
Total reclassification adjustments	(574)
Total change	(5,714)
Balance at December 31, 2010	$ 8,618
Net (gain) loss	**4,980**
Change in prior service costs/transition obligation	**—**
Reclassification adjustments:	
Amortization of transition obligation	**(228)**
Amortization of prior service costs	**188**
Amortization of net gain (loss)	**(234)**
Total reclassification adjustments	**(274)**
Total change	**4,706**
Balance at December 31, 2011	**$13,324**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2011	2010	2009
		(in thousands)	
Service cost	**$ 1,012**	$ 1,305	$ 1,328
Interest cost	**4,292**	4,763	5,535
Expected return on plan assets	**(1,763)**	(1,826)	(1,783)
Net amortization	**274**	574	919
Net postretirement cost	**$ 3,815**	$ 4,816	$ 5,999

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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2012	$ 5,003	$ (584)	$ 4,419
2013	5,366	(643)	4,723
2014	5,683	(717)	4,966
2015	6,046	(791)	5,255
2016	6,325	(871)	5,454
2017 to 2021	34,852	(4,503)	30,349

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**—**	—
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	20%	**22%**	23%
International equity	20	**20**	22
Fixed income	40	**40**	38
Special situations	2	**—**	—
Real estate investments	11	**11**	10
Private equity	7	**7**	7
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

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Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

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The fair values of pension plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 47,911	$ 22,115	$ —	$ 70,026
International equity*	49,250	14,111	—	63,361
Fixed income:				
U.S. Treasury, government, and agency bonds	—	17,960	—	17,960
Mortgage- and asset-backed securities	—	5,605	—	5,605
Corporate bonds	—	34,552	112	34,664
Pooled funds	—	15,757	—	15,757
Cash equivalents and other	28	5,773	—	5,801
Real estate investments	9,119	—	32,434	41,553
Private equity	—	—	24,151	24,151
Total	$106,308	$115,873	$56,697	$278,878

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 52,553	$ 21,208	$ 28	$ 73,789
International equity*	53,006	18,377	—	71,383
Fixed income:				
U.S. Treasury, government, and agency bonds	—	12,629	—	12,629
Mortgage- and asset-backed securities	—	10,250	—	10,250
Corporate bonds	—	24,663	85	24,748
Pooled funds	—	8,353	—	8,353
Cash equivalents and other	85	19,849	—	19,934
Real estate investments	7,645	—	27,976	35,621
Private equity	—	—	26,475	26,475
Total	$113,289	$115,329	$54,564	$283,182
Liabilities:				
Derivatives	(28)	—	—	(28)
Total	$113,261	$115,329	$54,564	$283,154

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in thousands)		
Beginning balance	**$27,976**	**$26,475**	$21,195	$21,498
Actual return on investments:				
Related to investments held at year end	**2,964**	**(498)**	3,959	4,313
Related to investments sold during the year	**830**	**1,951**	747	747
Total return on investments	**3,794**	**1,453**	4,706	5,060
Purchases, sales, and settlements	**664**	**(3,777)**	2,075	(83)
Transfers into/out of Level 3	**—**	**—**	—	—
Ending balance	**$32,434**	**$24,151**	$27,976	$26,475

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The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments are presented in the tables below based on the nature of the investment.

As of December 31, 2011:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$2,733	$ 1,260	$ —	$ 3,993
International equity*	2,807	804	—	3,611
Fixed income:				
U.S. Treasury, government, and agency bonds	—	4,796	—	4,796
Mortgage- and asset-backed securities	—	320	—	320
Corporate bonds	—	1,968	—	1,968
Pooled funds	—	898	—	898
Cash equivalents and other	1	987	—	988
Real estate investments	520	—	1,851	2,371
Private equity	—	—	1,377	1,377
Total	$6,061	$11,033	$3,228	$20,322

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2010:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$3,049	$ 1,230	$ 1	$ 4,280
International equity*	3,076	1,068	—	4,144
Fixed income:				
U.S. Treasury, government, and agency bonds	—	4,632	—	4,632
Mortgage- and asset-backed securities	—	596	—	596
Corporate bonds	—	1,431	—	1,431
Pooled funds	—	485	—	485
Cash equivalents and other	4	1,408	—	1,412
Real estate investments	442	—	1,625	2,067
Private equity	—	—	1,538	1,538
Total	$6,571	$10,850	$3,164	$20,585

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	**$1,625**	**$1,538**	$1,475	$1,497
Actual return on investments:				
Related to investments held at year end	**141**	**(29)**	29	47
Related to investments sold during the year	**47**	**85**	—	—
Total return on investments	**188**	**56**	29	47
Purchases, sales, and settlements	**38**	**(217)**	121	(6)
Ending balance	**$1,851**	**$1,377**	$1,625	$1,538

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2011, 2010, and 2009 were $3.8 million, $3.8 million, and $3.9 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by the Company. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated the Company as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled the Company's transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with the Company and several other utilities to investigate and remediate the site. The feasibility study/presumptive remedy document was originally filed with TCEQ in June 2011 and remains under consideration by the agency. Amounts expensed and accrued during 2009, 2010, and 2011 related to this work were not material. The Company currently has $0.4 million recorded to other deferred credits and liabilities on the balance sheet for potential remediation. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by the Company are expected to be recovered through the Environmental Compliance Overview (ECO) Plan.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

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FERC Matters

In 2008, the Company filed a request with the FERC for the Company's revised wholesale Municipal and Rural Association (MRA) cost-based electric tariff (Tariff) and revised rates under the Tariff. Prior to making this filing, the Company reached a settlement with all of its customers who take service under the Tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $5.8 million, effective in January 2009. In addition, the settlement agreement allows the Company to increase its annual accrual for the wholesale portion of property damage to $303,000 per year, to defer any property damage costs prudently incurred in excess of the wholesale property damage reserve balance, and to defer the wholesale portion of the generation screening and evaluation costs associated with the Kemper IGCC. The settlement agreement also provided that the Company will not seek a change in wholesale full-requirements rates before November 1, 2010, except for changes associated with the fuel adjustment clause and the ECM, changes associated with property damages that exceed the amount in the wholesale property damage reserve, and changes associated with costs and expenses associated with environmental requirements affecting fossil fuel generating facilities. In 2008, the Company received notice that the FERC had accepted the filing effective November 1, 2008, and the revised monthly charges were applied beginning January 1, 2009. As result of the order, the Company reclassified $9.3 million of previously expensed generation screening and evaluation costs to a regulatory asset. See "Integrated Coal Gasification Combined Cycle" herein for additional information.

In October 2010, the Company filed with the FERC a request for revised rates under its Tariff. Prior to making this filing, the Company reached a settlement with all of its customers who take service under the Tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $4.1 million, effective January 1, 2011. In addition, the settlement agreement allowed the Company to implement an emissions allowance cost clause, effective January 1, 2011. The emissions allowance cost clause contains an over and under recovery provision similar to the fuel recovery clause and was projected to collect $6.9 million in 2011. The settlement agreement also provided for collection of $2.8 million of 2010 emissions allowance expense for the period of September 2010 through December 2010 and allowed the Company to defer the wholesale portion of the income tax expense associated with the change in taxability of the federal subsidy under the Patient Protection and Affordable Care Act (PPACA) and the Health Care and Education Reconciliation Act of 2010 (together with PPACA, the Acts). In December 2010, the Company received notice that the FERC had accepted the filing effective December 21, 2010. As a result of the FERC acceptance, the $2.8 million of emission allowance revenue is included in the statements of income for 2010. Beginning January 1, 2011, the Company implemented the wholesale emissions allowance cost clause and revised monthly charges for the increase in annual base wholesale revenues.

On November 2, 2011, the Company filed a request with the FERC for revised rates under its Tariff. The requested revised rates provide for an increase in annual base wholesale revenues in the amount of approximately $32 million, effective January 1, 2012. In this filing, the Company is also (i) seeking approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) seeking authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) seeking authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules. On December 29, 2011, the Company received an order from the FERC accepting, but suspending for a nominal period, the proposed rate change and establishing a hearing and settlement procedure if an agreement with the wholesale customers could not be reached. On January 20, 2012, the Company reached a settlement agreement with its wholesale customers, which has been executed by all parties. The settlement agreement is currently under review by the FERC staff. The settlement agreement provides that base rates under the Tariff will increase approximately $22.6 million over a 12-month period with revised rates to be effective April 1, 2012. In 2012, the amount of base rate revenues to be received from the agreed upon increase will be approximately $17.0 million. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the CWIP recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The settlement agreement states that for future rate matters requiring regulatory accounting approval, the Company may follow for accounting and Tariff rate recovery purposes, the treatment allowed by the Mississippi PSC, if such treatment is not in violation of a FERC policy or rule and if agreed to by the wholesale customers. The Tariff customers specifically agreed to the same regulatory treatment for Tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (a) the accounting for Kemper IGCC-related costs that cannot be capitalized, (b) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (c) the establishment of a regulatory asset for certain potential plant retirement costs. The ultimate outcome of this matter cannot be determined at this time.

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Retail Regulatory Matters

Performance Evaluation Plan

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi PSC. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In 2004, the Mississippi PSC approved the Company's requested changes to PEP, including the use of a forward-looking test year, with appropriate oversight; annual, rather than semi-annual, filings; and certain changes to the performance indicator mechanisms. Rate changes are limited to 4% of retail revenues annually under the revised PEP. PEP will remain in effect until the Mississippi PSC modifies, suspends, or terminates the plan. In the 2004 order, the Mississippi PSC ordered that the MPUS and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change. In November 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. On January 10, 2011, the MPUS contested the filing. On June 7, 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates. On November 15, 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing. The ultimate outcome of this matter cannot be determined at this time.

In 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability-related maintenance costs beginning January 1, 2007 and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2011, the Company had fully amortized these costs.

In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4.

In March 2010, the Company submitted its annual PEP lookback filing for 2009, which recommended no surcharge or refund. In October 2010, the Company and the MPUS agreed and stipulated that no surcharge or refund is required. In November 2010, the Mississippi PSC accepted the stipulation.

On March 15, 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. On May 2, 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On or before March 15, 2012, the Company will submit its annual PEP lookback filing for 2011. The ultimate outcome of these matters cannot be determined at this time.

System Restoration Rider

The Company is required to make annual SRR filings to determine the revenue requirement associated with property damage. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Mississippi PSC periodically agrees on SRR revenue levels that are developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the MPUS or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses, and investment for the projected filing period, as well as the true-up for the prior period.

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In 2009, the Company submitted its 2009 SRR rate filing with the Mississippi PSC, which proposed that the SRR rate level remain at zero and the Company be allowed to accrue approximately $4.0 million to the property damage reserve in 2009. Subsequently in 2009, the Mississippi PSC issued an order requiring the Company to develop SRR factors designed to reduce SRR revenue by approximately $1.5 million from November 2009 to March 2010 under the new rate. On January 31, 2011, the Company submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that the 2011 SRR rate level remain at zero and the Company be allowed to accrue $3.6 million to the property damage reserve in 2011. On February 2, 2012, the Company submitted its 2012 SRR rate filing with the Mississippi PSC, which proposed that the 2012 SRR rate level remain at zero and the Company be allowed to accrue approximately $4 million to the property damage reserve in 2012. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

On February 14, 2012, the Company submitted its 2012 ECO Plan notice which proposed a 0.3% increase in annual revenues for the Company. The ultimate outcome of this matter cannot be determined at this time.

On February 14, 2011, the Company submitted its 2011 ECO Plan notice which proposed an immaterial decrease in annual revenues for the Company. In addition, the Company proposed to change the ECO Plan collection period to more appropriately match ECO revenues with ECO expenditures. On April 7, 2011, due to changes in ECO Plan cost projections, the Company submitted a revised 2011 ECO Plan which changed the requested annual revenues to a $0.9 million decrease. On May 5, 2011, the revised ECO Plan filing was approved by the Mississippi PSC with the new rates effective in May 2011.

In February 2010, the Company submitted its 2010 ECO Plan notice which proposed an increase in annual revenues for the Company of approximately $3.9 million. Due to changes in ECO Plan cost projections, in August 2010, the Company submitted a revised 2010 ECO Plan which reduced the requested increase in annual revenues to $1.7 million. In its 2010 ECO Plan filing, the Company proposed to change the true-up provision of the ECO Plan rate schedule to consider actual revenues collected in addition to actual costs. In October 2010, the Mississippi PSC held a public meeting to discuss the 2010 ECO Plan and issued an order approving the revised 2010 ECO Plan with the new rates effective in November 2010. The Company and the MPUS jointly agreed to defer the decision on the change in the true-up provision of the ECO Plan rate schedule. As a result of the change in the collection period requested in the Company’s 2011 ECO filing, the Company decided not to pursue the change in the true-up provision.

In July 2010, the Company filed a request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company’s portion being $330 million. The project is scheduled for completion in late 2015. The Company’s portion of the cost, if approved by the Mississippi PSC, is expected to be recovered through the ECO Plan. On May 5, 2011, in conjunction with the ECO Plan approval, the Mississippi PSC approved up to $19.5 million (with respect to the Company’s ownership portion) in additional spending for 2011 for the scrubber project. As of December 31, 2011, total project expenditures were $45.6 million, with the Company’s portion being $22.8 million. During the Mississippi PSC’s open meeting held on January 11, 2012, the Mississippi PSC requested additional information on the scrubber project and updates to the filing have been made. The ultimate outcome of these matters cannot be determined at this time.

On November 10, 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. On December 6, 2011, an order was granted by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

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Certificated New Plant

On April 27, 2011, the Company submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-A (CNP-A), a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. As part of the review of the mechanism, the Mississippi PSC will consider costs to be included as well as the allowed rate of return. CNP-A rate filings are made annually. The first filing was made on November 15, 2011 and requested an 11.66% increase in rates, or approximately $98 million annually, to recover these financing costs. If approved by the Mississippi PSC, CNP-A will remain in place thereafter until the end of the calendar year that the Kemper IGCC is placed into commercial service, which is projected to be 2014.

On August 9, 2011, the Company submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-B (CNP-B) to govern rates effective from the first calendar year after the Kemper IGCC is placed into commercial service through the first seven full calendar years of its operation. Under the proposed CNP-B, the Company's allowed cost of capital would be adjusted based on certain operational performance indicators. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred on November 15, 2011. On January 6, 2012, a revised filing was made with the Mississippi PSC requesting recovery over an 11 month period. The Mississippi PSC approved the retail fuel cost recovery factor on January 11, 2012, with the new rates effective in February 2012. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 2.2% of total 2011 retail revenue. At December 31, 2011, the amount of over recovered retail fuel costs included in the balance sheets was $42.4 million compared to $55.2 million at December 31, 2010. The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2012, the wholesale MRA fuel rate decreased, resulting in an annual decrease in an amount equal to 3.0% of total 2011 MRA revenue. Effective February 1, 2012, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 4.3% of total 2011 MB revenue. At December 31, 2011, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $14.3 million and $2.2 million compared to $17.5 million and $4.4 million, respectively, at December 31, 2010. In addition, at December 31, 2011, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $1.7 million. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factor will have no significant effect on the Company's revenues or net income, but will decrease annual cash flow.

On March 31, 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning on April 1, 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. On June 21, 2011, the Company and South Mississippi Electric Power Association (SMEPA) reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA on June 27, 2011.

In October 2010, the Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and ECM for 2010. The 2010 audit was completed in the first quarter 2011 with no audit findings. The 2011 audit of fuel-related expenditures began in the second quarter 2011 and was completed in the fourth quarter 2011 with no audit findings.

Storm Damage Cost Recovery

In March 2009, the Company filed with the Mississippi PSC its final accounting of the restoration costs relating to Hurricane Katrina and the storm operations center. On August 4, 2011, the Mississippi PSC issued an order approving the filing. The final net retail receivable of $3.2 million was recovered on October 21, 2011.

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Integrated Coal Gasification Combined Cycle

The Company is constructing the Kemper IGCC that will utilize an IGCC technology with an output capacity of 582 MWs. In May 2010, the Company filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming the Company's application for a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN.

The estimated cost of the plant is $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the CCPI2. The Mississippi PSC's order (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's proposal, and (3) approved financing cost recovery on construction work in progress (CWIP) balances, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by the Company in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $245 million. In May 2010, the Company executed a 40-year management fee contract with Liberty Fuels, which will develop, construct, and manage the mining operation. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operation operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits.

In 2009, the Company received notification from the Internal Revenue Service (IRS) formally certifying that the IRS allocated $133 million of Internal Revenue Code Section 48A tax credits (Phase I) to the Company. On April 19, 2011, the Company received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to the Company. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the plant during operations in accordance with the recapture rules for Section 48A investment tax credits. Through December 31, 2011, the Company received or accrued tax benefits totaling $99.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $77.4 million of these tax credits until after 2012. IRS guidelines allow these unused credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then.

In 2008, the Company requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida and, later in 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Through December 31, 2011, the Company has received grant funds of $245.3 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for its initial operation.

On March 10, 2011, the Sierra Club filed a lawsuit in the U.S. District Court for the District of Columbia against the DOE regarding the National Environmental Policy Act review process for the Kemper IGCC asking for a preliminary and permanent injunction on the issuance of CCPI2 funds and loan guarantees and a stay to any related construction activities based upon alleged deficiencies in the DOE's environmental impact statement. The Company intervened as a party in this lawsuit on May 18, 2011. On November 18, 2011, the U.S. District Court for the District of Columbia denied the Sierra Club's motion for preliminary injunction in the case and dismissed with prejudice the portion of the Sierra Club's claim relating to loan guarantees. On February 2, 2012, the Sierra Club filed for a voluntary dismissal with prejudice of all remaining claims against the DOE pending in the U.S. District Court for the District of Columbia.

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In March 2010, the MDEQ issued the Prevention of Significant Deterioration (PSD) air permit modification for the Kemper IGCC, which modifies the original PSD air permit issued in 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board unanimously affirmed the PSD air permit. On June 30, 2011, the Sierra Club appealed the final PSD air permit issued by the MDEQ to the Chancery Court of Kemper County, Mississippi. The Company has intervened as a party in this appeal.

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club's direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the Mississippi PSC's order authorizing the construction of the Kemper IGCC. On March 1, 2011, the Sierra Club appealed the Chancery Court's decision to the Mississippi Supreme Court.

In July 2010, the Company and SMEPA entered into an Asset Purchase Agreement whereby SMEPA agreed to purchase a 17.5% undivided ownership interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In December 2010, the Company and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

On March 4, 2011, the Company and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC. On May 19, 2011, the Company and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tenrgys, LLC, entered into a contract pursuant to which Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC.

On June 7, 2011, consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities for the Kemper IGCC. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

On September 9, 2011, the Company filed a request for confirmation of the Kemper IGCC's CPCN with the Mississippi PSC authorizing the acquisition, construction, and operation of approximately 61 miles of CO_2 pipeline infrastructure at an estimated capital cost of $141 million. On January 11, 2012, the Mississippi PSC affirmed the confirmation of the Kemper IGCC's CPCN for the acquisition, construction, and operation of the CO_2 pipeline.

As of December 31, 2011, the Company had spent a total of $943.3 million on the Kemper IGCC, including regulatory filing costs. Of this total, $917.8 million was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $21.4 million was recorded in other regulatory assets, $3.1 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

See Retail Regulatory Matters – "Certificated New Plant" herein for information on the proposed rate schedules related to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

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4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.

At December 31, 2011, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

Generating Plant	Percent Ownership	Gross Investment	Accumulated Depreciation
		(in thousands)	
Greene County			
Units 1 and 2	40%	$ 88,319	$ 42,274
Daniel			
Units 1 and 2	50%	$286,722	$142,376

The Company's proportionate share of plant operating expenses is included in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in thousands)	
Federal —			
Current	**$(27,099)**	$ 5,399	$ 77,619
Deferred	**65,206**	35,367	(32,980)
	38,107	40,766	44,639
State —			
Current	**(2,473)**	3,319	12,444
Deferred	**6,559**	2,190	(6,869)
	4,086	5,509	5,575
Total	**$ 42,193**	$46,275	$ 50,214

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	**$356,857**	$321,918
Basis differences	**48,268**	1,499
Energy cost management clause under recovered	**7,880**	10,216
Regulatory assets associated with asset retirement obligations	**7,557**	7,338
Pensions and other benefits	**18,283**	14,739
Regulatory assets associated with employee benefit obligations	**52,410**	35,021
Regulatory assets associated with the Kemper IGCC	**4,618**	4,640
Long-term service agreement	**5,231**	—
OCI	**—**	1
Other	**32,202**	25,677
Total	**533,306**	421,049
Deferred tax assets —		
Federal effect of state deferred taxes	**10,899**	11,323
Fuel clause over recovered	**30,050**	39,779
Other property basis differences	**2,918**	3,013
Pension and other benefits	**70,255**	53,213
Property insurance	**25,349**	23,880
Premium on long-term debt	**29,820**	—
Unbilled fuel	**14,951**	16,703
Long-term service agreement	**—**	4,740
Asset retirement obligations	**7,557**	7,338
Interest rate hedges	**5,763**	—
Investment tax credit carryforward	**77,400**	—
Other	**21,571**	21,614
Total	**296,533**	181,603
Total deferred tax liabilities, net	**236,773**	239,446
Portion included in (accrued) prepaid income taxes, net	**33,624**	42,521
Accumulated deferred income taxes	**$270,397**	$281,967

At December 31, 2011, the tax-related regulatory assets and liabilities were $26.5 million and $12.1 million, respectively. These assets are attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits. In 2010, the Company deferred $5.5 million as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The Company will amortize the regulatory asset to income tax expense over 10 years beginning January 1, 2012, as approved by the Mississippi PSC for the retail portion and over five years for the wholesale portion, as approved by the FERC.

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In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.3 million, $1.3 million, and $1.2 million for 2011, 2010, and 2009, respectively. At December 31, 2011, all investment tax credits available to reduce federal income taxes payable had been utilized. In 2010, the Company began recognizing investment tax credits associated with the construction expenditures related to the Kemper IGCC. At December 31, 2011, the Company had $99.6 million in unamortized investment tax credits associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $77.4 million of these tax credits until after 2012. IRS guidelines allow the resultant unused credits to be carried forward for 20 years expiring at the end of 2031, if not utilized before then.

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate was as follows:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.9**	2.8	2.7
Non-deductible book depreciation	**0.3**	0.3	0.3
Medicare subsidy	**(0.1)**	(0.2)	(0.4)
AFUDC-equity	**(6.3)**	(1.0)	(0.1)
Other	**(0.2)**	(0.8)	(0.8)
Effective income tax rate	**30.6%**	36.1%	36.7%

The Company's 2011 effective tax rate decreased from 2010 primarily due to the increase in non-taxable AFUDC equity related to increased construction expenditures.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits increased by $0.7 million, resulting in a balance of $5.0 million as of December 31, 2011.

Changes during the year in unrecognized tax benefits were as follows:

	2011	2010	2009
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 4,288**	$ 3,026	$ 1,772
Tax positions from current periods	**1,486**	868	1,309
Tax positions from prior periods	**(810)**	611	(55)
Reductions due to settlements	**—**	—	—
Reductions due to expired statute of limitations	—	(217)	—
Balance at end of year	**$ 4,964**	$ 4,288	$ 3,026

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The change in tax positions from current periods for 2011 relates primarily to the tax accounting method change for repairs-generation assets and State of Mississippi tax credits. The tax positions decrease from prior periods for 2011 relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See “Tax Method of Accounting for Repairs” below for additional information.

The impact on the Company’s effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 4,144**	$ 3,058	$ 3,026
Tax positions not impacting the effective tax rate	**820**	1,230	—
Balance of unrecognized tax benefits	**$ 4,964**	$ 4,288	$ 3,026

The tax positions impacting the effective tax rate for 2011 primarily relate to the State of Mississippi Investment Tax Credit and the production activities deduction tax position. See “Effective Tax Rate” above for additional information. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs - generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in thousands)	
Interest accrued at beginning of year	**$ 413**	$ 230	$ 203
Interest reclassified due to settlements	**—**	—	—
Interest accrued during the year	**267**	183	27
Balance at end of year	**$ 680**	$ 413	$ 230

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company’s unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or state audits, could also impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $5 million for the Company. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs - transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

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6. FINANCING

Bank Term Loans

In April 2011, the Company entered into a one-year $75 million aggregate principal amount long-term floating rate bank loan with a variable interest rate based on the one-month London Interbank Offered Rate (LIBOR). The proceeds of this loan were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

In September 2011, the Company entered into a one-year $40 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. In addition, the Company entered into a one-year extension of a $125 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The proceeds were used to repay outstanding short-term debt and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2011 and 2010, the Company had $240 million and $205 million of bank loans outstanding, respectively.

Senior Notes

In October 2011, the Company issued $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016 and $150 million aggregate principal amount of Series 2011B 4.75% Senior Notes due October 15, 2041. The Company also settled hedges totaling $150 million related to the Series 2011A issuance at a gain of approximately $1.4 million. This gain will be amortized to interest expense, in earnings, over five years. The Company also settled hedges totaling $150 million related to the Series 2011B issuance at a loss of approximately $0.5 million. This loss will be amortized to interest expense, in earnings, over 10 years. The net proceeds were used by the Company to pay amounts in connection with the purchase of Plant Daniel Units 3 and 4 as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units," and for general corporate purposes, including the Company's continuous construction program.

The Company had a total of $630.0 million and $330.0 million, respectively, of senior notes outstanding at December 31, 2011 and 2010.

Plant Daniel Revenue Bonds

In October 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2011 and 2010 was as follows:

	2011	2010
	(in millions)	
Capitalized leases	**$ 0.6**	$ 1.4
Bank term loans	**240.0**	205.0
Revenue bonds	**—**	50.0
Outstanding at December 31	**$ 240.6**	$ 256.4

Maturities applicable to total long-term debt are $240.6 million in 2012, $50.0 million in 2013, and $150.0 million in 2016. There are no scheduled maturities in 2014 and 2015.

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Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2011 and 2010 was $82.7 million.

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds. The Company had $50 million and $100 million of such obligations outstanding at December 31, 2011 and 2010, respectively. Such amounts are reflected in the statements of capitalization as long-term notes payable.

Assets Subject to Lien

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" for additional information.

Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock and depositary preferred stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2011, committed credit arrangements with banks were as follows:

Expires [(a)]				Executable Term-Loans	
2012	2014	Total	Unused	One Year	Two Years
		(in millions)			
$131	$165	$296	$296	$25	$41

(a) No credit arrangements expire in 2013, 2015, or 2016.

The Company expects to renew its credit arrangements, as needed, prior to expiration.

In connection with these credit arrangements, the Company agrees to pay commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes long-term debt payable to affiliated trusts and, in certain cases, other hybrid securities.

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In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2011, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowing.

This $296 million in unused credit arrangements provides required liquidity support to the Company's borrowings through a commercial paper program. The credit arrangements also provide support to the Company's variable rate tax-exempt pollution control revenue bonds totaling $40.1 million.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$—	—%	$ 7	0.21%	$70
December 31, 2010:					
Commercial paper	$—	—%	$ 12	0.28%	$63

(a) Average and maximum amounts are based upon daily balances during the period.

7. COMMITMENTS

Construction Program

The construction program of the Company is currently estimated to include a base level investment of $1.5 billion, $363 million, and $352 million for 2012, 2013, and 2014, respectively. Included in these estimated amounts are expenditures related to the Kemper IGCC of $1.3 billion, $124 million, and $74 million in 2012, 2013, and 2014, respectively, which are net of SMEPA's 17.5% expected ownership share of the Kemper IGCC of approximately $466 million and $16 million in 2013 and 2014, respectively. These estimated base level investment amounts include capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $87 million, $113 million, and $154 million for 2012, 2013, and 2014, respectively. These base level environmental expenditures do not include potential incremental environmental compliance investments associated with compliance with the EPA's final Mercury and Air Toxics Standards rule and proposed water and coal combustion byproducts rules, except with respect to $354 million which is included in the Company's base level capital investment in anticipation of these rules. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2011, significant purchase commitments were outstanding in connection with the continuous construction program. Capital improvements to generating, transmission, and distribution facilities, including those to meet environmental standards, will continue. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Long-Term Service Agreements

The Company has entered into a long-term service agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for Plant Daniel Units 3 and 4. The LTSA provides that GE will cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in the LTSA.

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In general, the LTSA is in effect through two major inspection cycles of the units. Scheduled payments to GE under the LTSA, which are subject to price escalation, are made monthly based on estimated operating hours of the units and are recognized as expense based on actual hours of operation. The Company has recognized expense of $12.9 million through October 20, 2011, $12.6 million for 2010, and $13.3 million for 2009, respectively, which is included in other operations and maintenance expense in the statements of income.

Effective October 21, 2011, concurrent with the Company's purchase of Plant Daniel Units 3 and 4, payments under the Company's LTSA with GE for Plant Daniel Units 3 and 4 are being recorded as prepayments on the balance sheet until the work is performed. Remaining payments to GE under the LTSA are currently estimated to total $90.2 million over approximately eight years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has entered into a LTSA with Alstom Power, Inc. for the purpose of securing maintenance support for its Chevron Unit 5 combustion turbine plant. In summary, the LTSA stipulates that Alstom Power, Inc. will perform all planned maintenance on the covered equipment, which includes the cost of all labor and materials. Alstom Power, Inc is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the LTSA.

In general, this LTSA is in effect through two major inspection cycles. Scheduled payments to Alstom Power, Inc., which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Payments to Alstom Power, Inc. under the LTSA are currently estimated to total $13.7 million over the remaining term of the LTSA, which is approximately five years. However, the LTSA contains various cancellation provisions at the option of the Company. Payments made to Alstom Power, Inc. under the LTSA prior to the performance of any planned maintenance are recorded as a prepayment in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed. After the LTSA expires, the Company expects to replace it with a new contract with similar terms.

Fuel Commitments

To supply a portion of its fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2011.

Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Commitments	
	Natural Gas	Coal
	(in thousands)	
2012	$159,394	$267,075
2013	149,890	49,765
2014	115,536	8,440
2015	95,005	960
2016	86,481	960
2017 and thereafter	146,169	35,520
Total	$752,475	$362,720

Coal commitments include a management fee of $38.1 million over the term of the executed 40-year management contract with Liberty Fuels beginning in 2014 related to the Kemper IGCC. Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The credit rating of Southern Power is currently below that of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

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Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense for the Company was $32.6 million, $38.6 million, and $39.1 million for 2011, 2010, and 2009 respectively, which includes the Plant Daniel Units 3 and 4 operating lease that ended October 20, 2011.

The Company and Gulf Power have jointly entered into operating lease agreements for the use of 745 aluminum railcars. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. In early 2011, one operating lease expired and the Company elected not to exercise the option to purchase. The remaining operating lease has 234 aluminum rail cars. The Company also has multiple operating lease agreements for the use of additional railcars that do not contain a purchase option. All of these leases are for the transport of coal to Plant Daniel.

The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $2.6 million in 2011, $3.5 million in 2010, and $4.0 million in 2009. The Company's annual railcar lease payments for 2012 through 2016 will average approximately $2.1 million and after 2016, lease payments total in aggregate approximately $0.5 million.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.4 million in 2011 and $0.7 million in 2010. The Company's annual lease payments for 2012 through 2014 will average approximately $0.2 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $7.5 million in 2011 and $8.4 million in 2010 related to barges and tow/shift boats. The Company's annual lease payments for 2012 through 2014 with respect to these barge transportation leases will average approximately $8.2 million.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2011, there were 271 current and former employees of the Company participating in the stock option program and there were 47 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

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The Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2010	1,843,370	$32.30
Granted	261,718	37.99
Exercised	(535,018)	31.31
Cancelled	(342)	32.33
Outstanding at December 31, 2011	**1,569,728**	**$33.59**
Exercisable at December 31, 2011	**967,865**	**$33.22**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $19.9 million and $12.6 million, respectively.

As of December 31, 2011, there was $0.2 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $0.8 million, $0.8 million, and $0.9 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $4.2 million, $2.7 million, and $0.4 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.6 million, $1.0 million, and $0.2 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units. The annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 36,981. During 2011, 35,067 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 1,218 performance share units were forfeited resulting in 70,830 unvested units outstanding at December 31, 2011.

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For the years ended December 31, 2011 and 2010, total compensation cost for performance share units recognized in income was $0.7 million and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.3 million and $0.1 million, respectively. As of December 31, 2011, there was $1.2 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
At December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 162	$—	$ 162
Foreign currency derivatives	—	1,526	—	1,526
Cash equivalents	133,900	—	—	133,900
Total	$133,900	$ 1,688	$—	$135,588
Liabilities:				
Energy-related derivatives	$ —	$51,152	$—	$ 51,152
Interest rate derivatives	—	15,208	—	15,208
Foreign currency derivatives	—	2,510	—	2,510
Total	$ —	$68,870	$—	$ 68,870

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As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
At December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 2,075	$—	$ 2,075
Foreign currency derivatives	—	3,419	—	3,419
Cash equivalents	160,200	—	—	160,200
Total	$160,200	$ 5,494	$—	$165,694
Liabilities:				
Energy-related derivatives	$ —	$45,845	$—	$ 45,845
Foreign currency derivatives	—	95	—	95
Total	$ —	$45,940	$—	$ 45,940

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice Period**
As of December 31, 2011	*(in thousands)*			
Cash equivalents:				
Money market funds	$ 133,900	None	Daily	Not applicable
As of December 31, 2010				
Cash equivalents:				
Money market funds	$ 160,200	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company’s investment in the money market funds.

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As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2011	**$1,343,596**	**$1,426,808**
2010	$ 716,399	$ 738,211

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

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At December 31, 2011, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Gas		
Net Purchased mmBtu*	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)		
31	2017	—

* mmBtu — million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2012 are immaterial.

Foreign Currency Derivatives

The Company may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings, however, the Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2011, the following foreign currency derivatives were outstanding:

	Notional Amount	**Forward Rate**	**Hedge Maturity Date**	**Fair Value Gain (Loss) December 31, 2011**
	(in millions)			*(in thousands)*
Fair value hedges of firm commitments				
	EUR 9.2	1.371 Dollars per Euro*	Various through March 2014	$(652)
Derivatives not designated as hedges				
	EUR18.1	1.317 Dollars per Euro*	N/A	(332)
Total				$(984)

* Weighted Average

During the year ended December 31, 2011, certain fair value hedges were de-designated. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company.

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Interest Rate Derivatives

The Company also enters into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of forecasted debt					
	$300	3-month LIBOR	2.66%*	April 2022	$(15)

* Weighted Average

For the year ended December 31, 2011, the Company had realized net gains of $0.8 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 are $0.8 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

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Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives, foreign currency derivatives, and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 125**	$ 830	Liabilities from risk management activities	**$36,455**	$27,459
	Other deferred charges and assets	**37**	1,238	Other deferred credits and liabilities	**14,697**	18,386
Total derivatives designated as hedging instruments for regulatory purposes		**$ 162**	$2,068		**$51,152**	$45,845
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ —**	$ 3	Liabilities from risk management activities	**$ —**	$ —
Interest rate derivatives:	Other current assets	**—**	—	Liabilities from risk management activities	**15,208**	—
Foreign currency derivatives:	Other current assets	**19**	2,403	Liabilities from risk management activities	**625**	66
	Other deferred charges and assets	**—**	1,016	Other deferred credits and liabilities	**46**	29
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 19**	$3,422		**$15,879**	$ 95
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ —**	$ 4	Liabilities from risk management activities	**$ —**	$ —
Foreign currency derivatives:	Other current assets	**1,507**	—	Liabilities from risk management activities	**1,839**	—
Total derivatives not designated as hedging instruments		**$1,507**	$ 4		**$ 1,839**	$ —
Total		**$1,688**	$5,494		**$68,870**	$45,940

All derivative instruments are measured at fair value. See Note 9 for additional information.

NOTES (continued)
Mississippi Power Company 2011 Annual Report

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$36,455**	$(27,459)	Other regulatory liabilities, current	**$125**	$ 830
	Other regulatory assets, deferred	**14,697**	(18,386)	Other regulatory liabilities, deferred	**37**	1,238
Total energy-related derivative gains (losses)		**$51,152**	$(45,845)		**$162**	$2,068

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**	**Amount**		
Derivative Category	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in thousands)				*(in thousands)*	
Energy-related derivatives	**$ (3)**	$ 3	$—	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**(14,361)**	—	—	Interest Expense	**48**	—	—
Total	**$(14,364)**	$ 3	$—		**$ 48**	$ —	$ —

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material. For the year ended December 31, 2011, the pre-tax effect of foreign currency derivatives not designated as hedging instruments was recorded as a regulatory asset and was immaterial to the Company.

For the twelve months ended December 31, 2011, the pre-tax losses from foreign currency derivatives designated as fair value hedging instruments, which include pre-tax losses associated with de-designated hedges prior to de-designation, on the Company's statements of income were $3.6 million. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of income.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2011, the fair value of derivative liabilities with contingent features was $6.4 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million.

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Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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Mississippi Power Company 2011 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 2011	**$263,276**	**$25,151**	**$14,617**
June 2011	**286,041**	**39,056**	**25,283**
September 2011	**325,766**	**53,171**	**38,019**
December 2011	**237,794**	**16,412**	**16,263**
March 2010	$283,638	$30,026	$15,253
June 2010	276,821	29,535	15,219
September 2010	327,083	55,033	33,593
December 2010	255,526	28,224	16,152

The Company’s business is influenced by seasonal weather conditions.

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011
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	2011	2010	2009	2008	2007
Operating Revenues (in thousands)	**$ 1,112,877**	$ 1,143,068	$ 1,149,421	$ 1,256,542	$ 1,113,744
Net Income After Dividends on Preferred Stock (in thousands)	**$ 94,182**	$ 80,217	$ 84,967	$ 85,960	$ 84,031
Cash Dividends on Common Stock (in thousands)	**$ 75,500**	$ 68,600	$ 68,500	$ 68,400	$ 67,300
Return on Average Common Equity (percent)	**10.54**	11.49	13.12	13.75	13.96
Total Assets (in thousands)	**$ 3,671,842**	$ 2,476,321	$ 2,072,681	$ 1,952,695	$ 1,727,665
Gross Property Additions (in thousands)	**$ 1,205,704**	$ 340,162	$ 95,573	$ 139,250	$ 114,927
Capitalization (in thousands):					
Common stock equity	**$ 1,049,217**	$ 737,368	$ 658,522	$ 636,451	$ 613,830
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**1,103,596**	462,032	493,480	370,460	281,963
Total (excluding amounts due within one year)	**$ 2,185,593**	$ 1,232,180	$ 1,184,782	$ 1,039,691	$ 928,573
Capitalization Ratios (percent):					
Common stock equity	**48.0**	59.8	55.6	61.2	66.1
Redeemable preferred stock	**1.5**	2.7	2.8	3.2	3.5
Long-term debt	**50.5**	37.5	41.6	35.6	30.4
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**151,805**	151,944	151,375	152,280	150,601
Commercial	**33,200**	33,121	33,147	33,589	33,507
Industrial	**496**	504	513	518	514
Other	**175**	187	180	183	181
Total	**185,676**	185,756	185,215	186,570	184,803
Employees (year-end)	**1,264**	1,280	1,285	1,317	1,299

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SELECTED FINANCIAL AND OPERATING DATA 2007-2011 (continued)
Mississippi Power Company 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in thousands):					
Residential	**$ 246,510**	$ 256,994	$ 245,357	$ 248,693	$ 230,819
Commercial	**263,256**	266,406	269,423	271,452	247,539
Industrial	**275,752**	267,588	269,128	258,328	242,436
Other	**6,945**	6,924	7,041	6,961	6,420
Total retail	**792,463**	797,912	790,949	785,434	727,214
Wholesale — non-affiliates	**273,178**	287,917	299,268	353,793	323,120
Wholesale — affiliates	**30,417**	41,614	44,546	100,928	46,169
Total revenues from sales of electricity	**1,096,058**	1,127,443	1,134,763	1,240,155	1,096,503
Other revenues	**16,819**	15,625	14,658	16,387	17,241
Total	**$ 1,112,877**	$ 1,143,068	$ 1,149,421	$ 1,256,542	$ 1,113,744
Kilowatt-Hour Sales (in thousands):					
Residential	**2,162,419**	2,296,157	2,091,825	2,121,389	2,134,883
Commercial	**2,870,714**	2,921,942	2,851,248	2,856,744	2,876,247
Industrial	**4,586,356**	4,466,560	4,329,924	4,187,101	4,317,656
Other	**38,684**	38,570	38,855	38,886	38,764
Total retail	**9,658,173**	9,723,229	9,311,852	9,204,120	9,367,550
Wholesale — non-affiliates	**4,009,637**	4,284,289	4,651,606	5,016,655	5,185,772
Wholesale — affiliates	**648,772**	774,375	839,372	1,487,083	1,026,546
Total	**14,316,582**	14,781,893	14,802,830	15,707,858	15,579,868
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.40**	11.19	11.73	11.72	10.81
Commercial	**9.17**	9.12	9.45	9.50	8.61
Industrial	**6.01**	5.99	6.22	6.17	5.61
Total retail	**8.21**	8.21	8.49	8.53	7.76
Wholesale	**6.52**	6.51	6.26	6.99	5.94
Total sales	**7.66**	7.63	7.67	7.90	7.04
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,229**	15,130	13,762	13,992	14,294
Residential Average Annual Revenue Per Customer	**$ 1,622**	$ 1,693	$ 1,614	$ 1,640	$ 1,545
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,156**	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,618**	2,792	2,392	2,385	2,294
Summer	**2,462**	2,638	2,522	2,458	2,512
Annual Load Factor (percent)	**59.1**	57.9	60.7	61.5	60.9
Plant Availability Fossil-Steam (percent)	**87.7**	93.8	94.1	91.6	92.2
Source of Energy Supply (percent):					
Coal	**34.9**	43.0	40.0	58.7	60.0
Oil and gas	**51.5**	41.9	43.6	28.6	27.1
Purchased power -					
From non-affiliates	**1.4**	1.3	3.3	4.4	3.0
From affiliates	**12.2**	13.8	13.1	8.3	9.9
Total	**100.0**	100.0	100.0	100.0	100.0

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SOUTHERN POWER COMPANY

FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2011 Annual Report

The management of Southern Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

/s/ Oscar C. Harper, IV
Oscar C. Harper, IV
President and Chief Executive Officer

/s/ Michael W. Southern
Michael W. Southern
Senior Vice President and Chief Financial Officer

February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the “Company”) (a wholly owned subsidiary of The Southern Company) as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, common stockholder’s equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-453 to II-476) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 24, 2012

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2011 Annual Report

OVERVIEW

Business Activities

Southern Power Company and its wholly-owned subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based prices in the wholesale market. The Company continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities.

The Company is continuing construction of an electric generating plant in Cleveland County, North Carolina. This plant will consist of four combustion turbine natural gas generating units with a total expected generating capacity of 720 megawatts (MW). The units are expected to begin commercial operation in December 2012. The Company has entered into long-term PPAs for 540 MWs of the generating capacity of the plant.

The Company is also continuing construction of the Nacogdoches biomass generating plant near Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in late 2009 and the plant is expected to begin commercial operation in June 2012. The entire output of the plant will be sold under a long-term PPA.

On March 15, 2011, The Southern Company (Southern Company) transferred its ownership in its wholly-owned subsidiary, Southern Renewable Energy, Inc. (SRE) to the Company. SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. In March 2010, SRE and Turner Renewable Energy, Inc. (TRE), through a subsidiary, entered into an engineering, construction, and procurement agreement with First Solar, Inc. for Plant Cimarron, a 30 MW solar photovoltaic plant near Cimarron, New Mexico, and assumed the associated PPA. In November 2010, Plant Cimarron began commercial operation. The transfer was accounted for by the Company as a transfer of net assets among entities under common control; therefore, the assets and liabilities of SRE were transferred from Southern Company to the Company at historical cost. The consolidated financial statements of the Company have been revised to include the financial condition and the results of operations of SRE since its inception in January 2010.

As of December 31, 2011, the Company had units totaling 7,908 MWs nameplate capacity in commercial operation. The weighted average remaining duration of the Company's wholesale contracts exceeds 11 years, which reduces remarketing risk. The Company has entered into long-term power sales agreements for an average of 80% of its available capacity for the next five years and 69% of its available capacity for the next 10 years. The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (the lower the better). Contract availability measures the percentage of scheduled hours that a unit was available. Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2011 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2011.

Earnings

The Company's 2011 net income was $162.2 million, a $30.9 million increase compared to 2010. This increase was primarily due to higher energy and capacity revenues. The increase was partially offset by higher fuel expenses, higher operations and maintenance expenses, loss on an early redemption of long-term debt, and higher depreciation and amortization.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

The Company's 2010 net income was $131.3 million, a $24.6 million decrease compared to 2009. This decrease was primarily due to higher operations and maintenance expenses, higher depreciation and amortization, and profit recognized in 2009 on a construction contract with the Orlando Utilities Commission (OUC) whereby the Company provided engineering, procurement, and construction services to build a combined cycle unit for the OUC. These decreases were partially offset by lower interest expense, net of amounts capitalized.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2011	**2011**	2010
		(in millions)	
Operating revenues	**$1,235.9**	**$105.6**	$183.7
Fuel	**454.8**	**63.3**	159.1
Purchased power	**131.3**	**(38.8)**	26.1
Other operations and maintenance	**171.5**	**23.3**	11.6
Loss (gain) on sale of property	**—**	**(0.5)**	(4.5)
Depreciation and amortization	**124.2**	**4.8**	21.2
Taxes other than income taxes	**17.7**	**(0.1)**	0.9
Total operating expenses	**899.5**	**52.0**	214.4
Operating income	**336.4**	**53.6**	(30.7)
Interest expense, net of amounts capitalized	**77.3**	**1.2**	(8.8)
Profit recognized on construction contract	**—**	**(0.5)**	(12.8)
Loss on extinguishment of debt	**(19.8)**	**(19.8)**	—
Other income (expense), net	**(1.2)**	**(0.7)**	(0.2)
Income taxes	**75.9**	**0.5**	(10.3)
Net income	**$ 162.2**	**$ 30.9**	$ (24.6)

Operating Revenues

Operating revenues in 2011 were $1.2 billion, a $105.6 million (9.3%) increase from 2010. This increase was primarily due to a $290.3 million increase in energy and capacity revenues under new PPAs and a $38.8 million increase in revenues from power sales under the Intercompany Interchange Contract (IIC). These increases were partially offset by a $177.7 million decrease in energy and capacity revenues associated with the expiration of PPAs, $29.3 million associated with lower revenues from energy sales that were not covered by PPAs, and $15.2 million associated with lower revenues from existing PPAs.

Operating revenues in 2010 were $1.1 billion, a $183.7 million (19.4%) increase from 2009. This increase was primarily due to a $378.4 million increase in energy and capacity revenues under new and existing PPAs, $80.8 million associated with higher revenues from energy sales that were not covered by PPAs due to more favorable weather in 2010 compared to 2009, and a $46.8 million increase in revenues from power sales under the IIC. These increases were partially offset by a $321.4 million decrease in energy and capacity revenues associated with the expiration of PPAs in December 2009 and May 2010.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges. Details of these PPA capacity and energy revenues are as follows:

	2011	2010	2009
		(in millions)	
Capacity revenues —			
Affiliates	**$146.5**	$190.6	$287.6
Non-affiliates	**322.7**	257.4	185.7
Total	**469.2**	448.0	473.3
Energy revenues —			
Affiliates	**39.3**	46.1	192.8
Non-affiliates	**482.9**	401.1	173.8
Total	**522.2**	447.2	366.6
Total PPA revenues	**$991.4**	$895.2	$839.9

Wholesale revenues that were not covered by PPAs totaled $237.8 million in 2011, which included $172.8 million of revenues from affiliated companies. Wholesale revenues that were not covered by PPAs totaled $228.2 million in 2010, which included $134.0 million of revenues from affiliated companies. These wholesale sales to affiliated companies were made in accordance with the IIC, as approved by the Federal Energy Regulatory Commission (FERC). These non-PPA wholesale revenues will vary from year to year depending on demand and the availability and cost of generating resources at each company that participates in the centralized operation and dispatch of the Southern Company system fleet of generating plants (power pool).

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's fuel and purchased power expenditures are as follows:

	2011	2010	2009
		(in millions)	
Fuel	**$454.8**	$391.5	$232.5
Purchased power-non-affiliates	**78.4**	72.7	79.3
Purchased power-affiliates	**52.9**	97.4	64.6
Total fuel and purchased power expenses	**$586.1**	$561.6	$376.4

In 2011, total fuel and purchased power expenses increased by $24.5 million (4.4%) compared to 2010. Total fuel and purchased power expenses increased $144.2 million, primarily due to a 28.0% increase in kilowatt-hours (KWH) generated and purchased. The increase was partially offset by a decrease of $119.7 million due to a 30.0% decrease in the cost of purchased power and a 12.1% decrease in the average cost of natural gas. In 2010, total fuel and purchased power expenses increased by $185.2 million (49.2%) compared to 2009. Total fuel and purchased power expenses increased $77.3 million primarily due to an 8.7% increase in the average cost of natural gas and a 36.4% increase in the cost of purchased power and $107.9 million due to an increase in KWHs generated and purchased.

In 2011, fuel expense increased by $63.3 million (16.2%) compared to 2010. Fuel expense increased $126.7 million primarily due to an increase in the volume of KWHs generated, partially offset by a $63.4 million decrease due to a 12.1% decline in the average cost of natural gas. In 2010, fuel expense increased by $159.1 million (68.4%) compared to 2009. Fuel expense increased $31.7 million primarily due to an 8.7% increase in the average cost of natural gas and $127.4 million due to an increase in KWHs generated.

In 2011, purchased power expense decreased $38.8 million (22.8%) compared to 2010. Purchased power expense decreased $56.3 million due to a 30.0% decrease in the average cost of purchased power, partially offset by a $17.5 million increase associated with an increase in the volume of KWHs purchased. In 2010, purchased power expense increased $26.1 million (18.1%) compared to 2009. Purchased power expense increased $45.6 million due to an increase in the average cost of purchased power, partially offset by a $19.5 million decrease due to fewer KWHs purchased.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

The Company's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is generally accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. The Company is responsible for the cost of fuel for units that are not covered under PPAs. Power from these units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate-owned generation, or external purchases.

Other Operations and Maintenance Expenses

In 2011, other operations and maintenance expenses increased $23.3 million (15.7%) compared to 2010. This increase was primarily due to an increase of $17.1 million related to generating plant scheduled outages and maintenance, mainly at Plants Stanton, Wansley, Harris, and West Georgia, an increase of $3.3 million related to labor costs across the fleet, and a $4.9 million increase in administrative and general expenses due to expenses associated with strategic planning, legal fees, and additional expenses in 2011 due to information technology upgrades. These increases were partially offset by a $4.1 million decrease attributable to additional expense recognized in 2010 associated with the passage of healthcare legislation.

In 2010, other operations and maintenance expenses increased $11.6 million (8.5%) compared to 2009. This increase was primarily due to an increase of $4.2 million related to generating plant outages and maintenance, mainly at Plants Stanton, Harris, and Franklin and $4.1 million of additional expense associated with the passage of healthcare legislation in March 2010.

Loss (Gain) on Sale of Property

In 2010, loss on sale of property decreased $4.5 million due to the divestiture of DeSoto County Generating Company, LLC (DeSoto) in December 2009.

Depreciation and Amortization

In 2011, depreciation and amortization increased $4.8 million (4.1%) compared to 2010. This increase was primarily related to an $8.0 million increase in depreciation rates associated with increased starts and run-hours at the Company's generating plants, which shortened the estimated depreciable life of some components, and a $3.3 million increase associated with the acquisition of Plant Cimarron. These increases were partially offset by a $7.5 million decrease due to higher expenses in 2010 related to equipment retirements.

In 2010, depreciation and amortization increased $21.2 million (21.6%) compared to 2009. This increase was primarily related to a $6.7 million increase associated with the acquisition of West Georgia Generating Company, LLC (West Georgia) and the related divestiture of DeSoto in December 2009, which resulted in an increase in property, plant, and equipment of $120.2 million. The increase was also due to $7.5 million of equipment retirements and a $6.5 million increase in depreciation rates related primarily to increased starts and run-hours at the Company's generating plants, which shortened the estimated depreciable life of some components.

See ACCOUNTING POLICIES — "Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates. See also Note 1 to the financial statements under "Depreciation" for additional information.

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Interest Expense, Net of Amounts Capitalized

In 2011, interest expense, net of amounts capitalized increased $1.2 million (1.6%) compared to 2010. This increase was primarily due to $5.9 million in interest expense associated with the issuance of new long-term debt, $0.7 million associated with settlements and changes in tax positions from prior periods, $0.6 million associated with losses on interest rate swaps on senior notes, and $0.5 million associated with an affiliate loan related to SRE in the first quarter 2011. These increases were partially offset by $5.9 million of additional capitalized interest associated with the construction of the Cleveland County combustion turbine generating plant and the Nacogdoches biomass plant and a $1.1 million decrease as the result of an early redemption of senior notes.

In 2010, interest expense, net of amounts capitalized decreased $8.8 million (10.4%) compared to 2009. This decrease was primarily due to $10.5 million of additional capitalized interest associated with the construction of the Cleveland County combustion turbine generating plant and the Nacogdoches biomass plant, partially offset by $0.7 million associated with an increase in interest expense on commercial paper and $0.7 million associated with interest rate swaps on senior notes.

Profit Recognized on Construction Contract

Profit recognized on the construction contract with the OUC whereby the Company has provided engineering, procurement, and construction services to build a combined cycle unit for the OUC was $0.5 million in 2010 and $13.3 million in 2009.

Loss on Extinguishment of Debt

In December 2011, the Company recorded a loss of $19.8 million in connection with the early redemption of senior notes primarily related to the payment of a make whole premium.

Other Income (Expense), Net

In 2011, other income (expense), net decreased $0.7 million compared to 2010. This decrease was primarily due to the reclassification from other comprehensive income (OCI) of an interest rate hedge associated with the early redemption of senior notes.

The change in other income (expense), net for 2010 as compared to 2009 was not material.

Income Taxes

In 2011, income taxes increased $0.5 million (0.7%) compared to 2010. This increase was primarily due to a $12.4 million increase associated with higher pre-tax earnings, a $5.0 million increase due to reduced tax benefit from the impact of convertible investment tax credits (ITCs) associated with the construction of the Nacogdoches biomass plant and Plant Cimarron, and a $2.1 million increase due to the loss of the production activities deduction. These increases were partially offset by a $14.5 million decrease associated with the application of a lower composite tax rate and a $3.7 million decrease related to higher than expected future utilization of net operating losses (NOLs) in the State of New Mexico.

In 2010, income taxes decreased $10.3 million (12.0%) compared to 2009. This decrease was primarily due to $12.0 million associated with lower pre-tax earnings and an $8.3 million decrease due to tax benefits from the impact of convertible ITCs associated with the construction of the Nacogdoches biomass plant and Plant Cimarron. These decreases were partially offset by a $3.3 million increase related to lower than expected future utilization of NOLs in the State of New Mexico and a $6.7 million increase in Alabama state taxes. Alabama's state tax liability is reduced by a deduction for federal income taxes paid. Due to increased bonus depreciation and incentives associated with new plant construction, the federal tax liability was significantly reduced, resulting in a higher overall state tax expense. Also contributing to the increase in state taxes was the application of the resulting higher state tax rate to the deferred income tax balance.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

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FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's target market areas; the successful remarketing of capacity as current contracts expire; and the Company's ability to execute its acquisition strategy and to construct generating facilities.

Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations. General economic conditions have lowered demand and have negatively impacted capacity revenues under the Company's PPAs where the amounts purchased are based on demand. The Company is unable to predict whether demand under these PPAs will return to pre-recession levels. The timing and extent of the economic recovery is uncertain and will impact future earnings.

Power Sales Agreements

The Company's sales are primarily through long-term PPAs. The Company is working to maintain and expand its share of the wholesale market. The Company expects that capacity needs will develop within its existing market areas beginning in 2015.

The Company's PPAs consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

The Company has entered into the following PPAs over the past three years:

	Date	MWs	Plant	Contract Term
2011				
Georgia Power Company [(a)]	June 2011	75	Dahlberg	1/15-5/30
Georgia Power Company [(a)]	June 2011	625	Harris [(b)]	6/15-5/30
Georgia Power Company [(a)]	June 2011	298	West Georgia	1/15-5/30
Morgan Stanley Capital Group	August 2011	250	Franklin	1/16-12/25
Tampa Electric Company (TECO) [(c)]	December 2011	160	Oleander	1/13-12/15[(c)]
2010				
Tri State Generation and Transmission Association, Inc. [(d)]	March 2010	30	Cimarron	12/10-11/35
City of Seneca	June 2010	30 [(i)]	Unassigned	7/10-6/15
Georgia Electric Membership Corporation (EMCs) [(e)]	October 2010 [(e)]	423 [(i)]	Unassigned	1/15-12/27[(e)]
2009				
Municipal Electric Authority of Georgia (MEAG Power) [(f)]	December 2009	157 [(i)]	West Georgia	12/09-4/29
Georgia Energy Cooperative, Inc. (GEC) [(f)]	December 2009	151	West Georgia	6/10-5/30
Austin Energy [(g)]	October 2009	100	Nacogdoches	6/12-5/32
Seminole Electric Cooperative, Inc. (Seminole) [(h)]	June 2009	509	Oleander	1/16-5/21

(a) These agreements are subject to approval by the Georgia Public Service Commission (PSC) and by the FERC. These agreements also include an early termination provision through March 27, 2012 that allows Georgia Power Company (GPC) to terminate one or more of the agreements if GPC does not need to retire coal-fired units as a result of certain new and proposed Environmental Protection Agency (EPA) rules and regulations. Early termination will result in payment by GPC of a fee of up to $20 million.

(b) This agreement is contracted with Plant Franklin from June 2015 through December 2015.

(c) This agreement is subject to approval by the Florida PSC. The agreement also contains an early termination provision through December 2012 that allows TECO to terminate the agreement if they are unable to procure necessary transmission services. This agreement, signed on December 16, 2011, has an option for extension which, if signed by July 1, 2013, would extend the term to December 2017.

(d) Contract assumed by SRE in March 2010.

(e) These agreements, signed in October and December 2010, are extensions of current agreements with 11 Georgia EMCs. Nine agreements were extended from 2015 through 2024, one agreement was extended from 2018 through 2027, and one agreement was extended from 2018 through 2024.

(f) Assumed contract through the West Georgia acquisition in 2009.

(g) Assumed contract through the Nacogdoches Power LLC acquisition in 2009. Commercial operation of Plant Nacogdoches is expected to begin in June 2012.

(h) This agreement is an extension of the current agreement with Seminole for Plant Oleander.

(i) Represents average annual capacity purchases.

The Company has PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and an energy marketing firm. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

As a general matter, existing PPAs provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

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Fixed and variable operation and maintenance costs will be recovered through capacity charges based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, the Company has long-term service contracts with General Electric International, Inc., Siemens Electric, Inc., and First Solar, Inc. to reduce its exposure to certain operation and maintenance costs relating to such vendors' applicable equipment. See Note 7 to the financial statements under "Long-Term Service Agreements" for additional information.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that Standard & Poor's, a division of The McGraw Hill Companies, Inc. (S&P), or Moody's Investors Service (Moody's) downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company has entered into long-term power sales agreements for an average of 80% of its available capacity for the next five years and 69% of its available capacity for the next 10 years.

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts, can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million.

In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

Air Quality

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas in which the Company operates fossil fuel generating assets were designated as nonattainment. The new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

On March 21, 2011, the EPA published a final Industrial Boiler (IB) Maximum Achievable Control Technology (MACT) rule establishing emissions limits for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. At the same time, the EPA issued a notice of intent to reconsider the final rule and, on May 16, 2011, the EPA issued an administrative stay to prevent the rule from becoming effective. On December 2, 2011, the EPA proposed a reconsideration rule to change certain aspects of the final rule. On January 9, 2012, however, the U.S. District Court for the District of Columbia Circuit vacated the EPA's administrative stay. Although the U.S. District Court for the District of Columbia Circuit's decision would allow the original IB MACT rule to become effective, the EPA has indicated that it will not implement the rule until the EPA's proposed revisions can be finalized. The effect of the regulatory proceedings will depend on the final form of the revised regulations and the outcome of any legal challenges and cannot be determined at this time.

Each of the states in which the Company has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the Company) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets.

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Water Quality

On April 20, 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. If finalized as proposed, some of the Company's facilities may be subject to additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in additional capital expenditures and compliance costs if such costs are not recovered through PPAs. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific requirements of the final rule and, therefore, cannot be determined at this time.

Global Climate Issues

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

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Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level are likely to result in additional compliance costs, including capital expenditures. Additional compliance costs could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Company's 2010 greenhouse gas emissions were approximately 7 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2011 greenhouse gas emissions on the same basis is approximately 10 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

The Company continues to evaluate its future energy and emissions profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions, including Plant Cimarron in Springer, New Mexico and the construction of the Nacogdoches biomass plant in Sacul, Texas.

Income Tax Matters

Convertible Investment Tax Credits

In February 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. The Company received ITCs under the renewable energy incentives related to the Nacogdoches biomass plant and Plant Cimarron which have had a material impact on cash flows and net income. The Company will continue to receive ITCs related to the construction of the Nacogdoches biomass plant. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013. Due to the significant amount of estimated bonus depreciation for 2012, tax credit utilization will be reduced. Consequently, it is estimated there will be a positive cash flow benefit of between $115 million and $150 million in 2012.

Construction Projects

Cleveland County Units 1-4

In 2008, the Company announced that it will build an electric generating plant in Cleveland County, North Carolina. The plant will consist of four combustion turbine natural gas generating units with a total generating capacity of 720 MWs. The units are expected to begin commercial operation in December 2012. Construction costs incurred through December 31, 2011 were $265.6 million. The total estimated cost of the project is expected to be between $335 million and $365 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY — "Capital Requirements and Contractual Obligations" herein.

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Nacogdoches Biomass Plant

In 2009, the Company acquired all of the outstanding membership interests of Nacogdoches Power, LLC (Nacogdoches) from American Renewables LLC, the original developer of the project. Nacogdoches is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in 2009 and the plant is expected to begin commercial operation in June 2012. Construction costs incurred through December 31, 2011 were $392.4 million. The total estimated cost of the project is expected to be between $470 million and $490 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY — "Capital Requirements and Contractual Obligations" herein.

Other Matters

The Company is involved in various other litigation and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with generally accepted accounting principles (GAAP). Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, cash flow hedges, and mark-to-market transactions. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY — "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating or capital. All of the Company's power sales contracts classified as leases are accounted for as operating leases.

Non-Derivative and Normal Sale Derivative Transactions

If the sales contract is not considered a lease, the Company further considers the following factors to determine proper transaction classification:

- Assessing whether a sales contract meets the definition of a derivative;
- Assessing whether a sales contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are exempt from fair value accounting in accordance with GAAP. As a result, such transactions are accounted for as executory contracts. The related revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues are recorded on a gross or net basis in accordance with GAAP. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues for the years ended December 31, 2011, 2010, and 2009.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are marked to market through OCI over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

Mark-to-Market Transactions

Contracts for sales and purchases of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are marked-to-market and recorded directly through net income.

Impairment of Long Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPAs and goodwill resulting from acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

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Acquisition Accounting

The Company has been engaged in a strategy of acquiring assets. The Company has accounted for acquisitions from non-affiliates under the acquisition method in accordance with GAAP. Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price of each acquisition was allocated to the fair value of the identifiable assets and liabilities. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions have been expensed as incurred.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by management. The primary assets in property, plant, and equipment are power plants, all of which have an estimated composite life ranging from 18 to 36 years. These lives reflect a weighted average of the significant components (retirement units) that make up the plants. Key judgments impacting the estimated lives of component parts include estimates of run-hours and starts which can impact the future utility of these components. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Convertible Investment Tax Credits

Under the ARRA, certain costs related to the Nacogdoches biomass plant and Plant Cimarron construction are eligible for ITCs or cash grants. The Company has elected to receive ITCs. A high degree of judgment is required in determining which construction expenditures qualify for ITCs. See Note 1 to the financial statements under "Convertible Investment Tax Credits" for additional information.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2011. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $412.4 million in 2011, compared to $326.8 million in 2010. This increase was primarily due to an increase in convertible ITCs received in 2011. Net cash used for investing activities totaled $328.4 million in 2011, compared to $408.1 million in 2010. This decrease was primarily due to the Plant Cimarron acquisition in December 2010. Net cash used for financing activities totaled $81.3 million in 2011, compared to $88.3 million of cash provided from financing activities in 2010. This decrease was primarily due to a decrease in notes payable in 2011 associated with the repayment of an affiliate loan related to SRE, partially offset by an increase in capital contributions from Southern Company.

Net cash provided from operating activities totaled $326.8 million in 2010, compared to $318.1 million in 2009. This increase was mainly due to an increase in convertible ITCs. Net cash used for investing activities totaled $408.1 million in 2010, compared to $364.1 million in 2009. This increase was primarily due to the Plant Cimarron acquisition and an increase in construction work in progress related to construction activities at Cleveland County and Nacogdoches, partially offset by the Nacogdoches and West Georgia acquisitions in 2009. Net cash provided from financing activities totaled $88.3 million in 2010, compared to $15.2 million in 2009. The increase in cash provided was primarily due to an increase in capital contributions from Southern Company and the issuance of notes payable due to the acquisition of SRE.

Significant asset changes in the balance sheet during 2011 include a decrease in prepaid income tax due to the receipts of ITCs and an increase in construction work in progress related to Cleveland County and Nacogdoches construction activities.

Significant liability and stockholder's equity changes in the balance sheet during 2011 include a decrease in notes payable due to the repayment of an affiliate loan related to SRE and an increase in deferred convertible ITCs due to additional spending on the Nacogdoches biomass plant.

Sources of Capital

The Company may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. The Company expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company's current liabilities frequently exceed current assets due to the use of short-term debt as a funding source, as well as cash needs which can fluctuate significantly due to the seasonality of the business.

At December 31, 2011, the Company had approximately $16.9 million of cash and cash equivalents. During 2011, the Company terminated its existing credit arrangement and entered into a $500 million committed credit facility (Facility) expiring in 2016. As of December 31, 2011, the total amount available under the Facility was $500 million.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. The Facility also contains a cross default provision that would be triggered if the Company defaulted on other indebtedness above a specified threshold. The cross default provision is restricted only to indebtedness of the Company. As of December 31, 2011, the Company was in compliance with all covenants in the Facility.

There were no borrowings outstanding under the Company's prior facility at December 31, 2010. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

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Proceeds from these credit arrangements may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

Details of short-term borrowings as of December 31, 2011 and December 31, 2010 were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	**$ 180**	**0.48%**	**$ 175**	**0.38%**	**$ 305**
December 31, 2010:					
Commercial paper	$ 204	0.41%	$ 169	0.40%	$ 259

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, the line of credit, and cash.

Financing Activities

During 2011, the Company prepaid $3.7 million on a long-term debt related to SRE.

On September 22, 2011, the Company issued $300 million aggregate principal amount of Series 2011A 5.15% Senior Notes due September 15, 2041. On November 17, 2011, the Company issued an additional $275 million of the same series of notes. Upon the completion of this offering, the aggregate principal amount of the outstanding Series 2011A 5.15% Senior Notes was $575 million. On December 19, 2011, the net proceeds from the issuance were used to redeem $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

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The maximum potential collateral requirements under these contracts at December 31, 2011 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	443
Below BBB- and/or Baa3	1,205

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

In addition, through the acquisition of Plant Rowan, the Company assumed a PPA with North Carolina Municipal Power Agency No. 1 that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

The Company is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, the Company takes advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

At December 31, 2011, the Company had no variable long-term debt outstanding. Therefore, there would be no effect on annualized interest expense related to long-term debt if the Company sustained a 100 basis point change in interest rates. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the years ended December 31 were as follows:

	2011 Changes	2010 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (3.5)**	$(3.5)
Contracts realized or settled	**5.6**	1.5
Current period changes [(a)]	**(11.3)**	(1.5)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (9.2)**	$(3.5)

(a) Current period changes also include changes in the fair value of new contracts entered into during the period, if any.

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For the year ended December 31, 2011, there was a $5.7 million decrease in the fair value positions of the energy related derivative contracts associated with both power and natural gas positions. For the year ended December 31, 2010, there was no change in the total fair value of the energy-related derivative contracts.

The net hedge positions at December 31, 2011 and December 31, 2010 and respective period end dates that support these changes were as follows:

	December 31, 2011	December 31, 2010
Power – net purchased or (sold)		
Megawatt hours (MWH) (in millions)	**0.1**	(0.9)
Weighted average contract cost per MWH above (below) market prices (in dollars)	**$(1.04)**	$(2.33)
Natural gas net purchased		
Commodity – million British thermal unit (mmBtu)	**8.3**	13.0
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$ 1.18**	$ 0.11

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**2011**	2010
	(in millions)	
Cash flow hedges	**$(0.8)**	$(1.0)
Not designated	**(8.4)**	(2.5)
Total fair value	**$(9.2)**	$(3.5)

Gains and losses on energy-related derivatives used by the Company to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2011, 2010, and 2009 for energy-related derivative contracts that are not hedges were $(5.9) million, $(1.5) million, and $(5.2) million, respectively. Included in these amounts are losses on derivative contracts reimbursable by third parties in the amount of $7.7 million, $0.8 million, and $0.4 million for 2011, 2010, and 2009, respectively, associated with hedging fuel price risk of certain PPA customers. To the extent unrealized amounts are reimbursable, there is no impact to net income.

The Company uses over-the-counter contracts that are not exchange-traded but are fair valued using prices which are actively quoted, and thus fall into Level 2. See Note 8 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(9.2)	(9.4)	(0.2)	0.4
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(9.2)	$(9.4)	$(0.2)	$ 0.4

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related derivative contracts. The Company only enters into agreements with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $187 million for 2012, $419 million for 2013, and $272 million for 2014. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. The Company is currently constructing a four-unit combustion turbine generating plant in Cleveland County, North Carolina and a biomass generating facility in Sacul, Texas. See FUTURE EARNINGS POTENTIAL — "Construction Projects" herein for additional information.

In addition, pursuant to an agreement between SRE and TRE, on or after the fifth anniversary of the commercial operation date of Plant Cimarron, TRE may require SRE to purchase its minority interest in the plant at fair market value.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

Contractual Obligations

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing (c)	Total
			(in millions)			
Long-term debt (a) —						
Principal	$ —	$ —	$ 525.0	$ 776.1	$—	$1,301.1
Interest	68.0	136.0	98.6	985.6	—	1,288.2
Energy-related derivative obligations (b)	9.6	0.2	—	—	—	9.8
Operating leases	0.5	1.0	0.9	22.3	—	24.7
Unrecognized tax benefits and interest (c)	—	—	—	—	2.6	2.6
Purchase commitments (d) —						
Capital (e)	158.9	557.4	—	—	—	716.3
Natural gas (f)	399.4	638.2	435.0	172.7	—	1,645.3
Biomass fuel (g)	0.9	—	—	—	—	0.9
Purchased power (h)	49.2	102.0	91.8	203.4	—	446.4
Long-term service agreements (i)	56.7	122.0	159.5	629.2	—	967.4
Emissions reduction credit	1.3	—	—	—	—	1.3
Total	$744.5	$1,556.8	$1,310.8	$2,789.3	$2.6	$6,404.0

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) The timing related to the realization of $2.6 million in unrecognized tax benefits and corresponding interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements for additional information.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses were $171.5 million, $148.2 million, and $136.7 million, for 2011, 2010, and 2009, respectively.

(e) The Company provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under long-term service agreements.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(g) Biomass fuel commitments are based on minimum committed tonnage of wood waste purchases for Plant Nacogdoches. Plant Nacogdoches is expected to begin commercial operation in June 2012.

(h) Purchased power commitments of $35.4 million in 2012, $72.9 million in 2013-2014, $75.9 million in 2015-2016, and $203.4 million after 2016 will be resold under a third party agreement to EnergyUnited. The purchases will be resold at cost.

(i) Long-term service agreements include price escalation based on inflation indices.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning current and proposed environmental regulations and related estimated expenditures, access to sources of capital, financing activities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, timing of expected future capacity need in existing markets, completion of construction projects, filings with federal regulatory authorities, plans and estimated costs for new generation resources, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water and emissions of sulfur, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- advances in technology;
- state and federal rate regulations;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Southern Power Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Operating Revenues:			
Wholesale revenues, non-affiliates	**$ 870,607**	$ 752,772	$394,366
Wholesale revenues, affiliates	**358,585**	370,630	544,415
Other revenues	**6,769**	6,939	7,870
Total operating revenues	**1,235,961**	1,130,341	946,651
Operating Expenses:			
Fuel	**454,790**	391,535	232,466
Purchased power, non-affiliates	**78,368**	72,657	79,355
Purchased power, affiliates	**52,924**	97,408	64,587
Other operations and maintenance	**171,538**	148,238	136,655
Loss (gain) on sale of property	**—**	478	4,977
Depreciation and amortization	**124,204**	119,333	98,135
Taxes other than income taxes	**17,686**	17,831	16,920
Total operating expenses	**899,510**	847,480	633,095
Operating Income	**336,451**	282,861	313,556
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(77,334)**	(76,120)	(84,963)
Profit recognized on construction contract	**—**	470	13,296
Loss on extinguishment of debt	**(19,806)**	—	—
Other income (expense), net	**(1,223)**	(546)	(374)
Total other income and (expense)	**(98,363)**	(76,196)	(72,041)
Earnings Before Income Taxes	**238,088**	206,665	241,515
Income taxes	**75,857**	75,356	85,663
Net Income	**$ 162,231**	$ 131,309	$155,852

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2011, 2010, and 2009
Southern Power Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Net Income	**$162,231**	$131,309	$155,852
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $55, $591, and $(664), respectively	**65**	938	(1,044)
Reclassification adjustment for amounts included in net income, net of tax of $4,837, $3,894, and $3,875, respectively	**7,125**	6,444	5,700
Total other comprehensive income (loss)	**7,190**	7,382	4,656
Comprehensive Income	**$169,421**	$138,691	$160,508

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010, and 2009
Southern Power Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in thousands)	
Operating Activities:			
Net income	**$ 162,231**	$ 131,309	$ 155,852
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**138,787**	133,109	110,427
Deferred income taxes	**4,481**	64,530	22,950
Convertible investment tax credits received	**84,723**	26,400	16,800
Deferred revenues	**(10,594)**	(5,586)	2,288
Mark-to-market adjustments	**8,000**	1,492	5,204
Loss on extinguishment of debt	**19,806**	—	—
Accumulated billings on construction contract	**—**	401	48,451
Accumulated costs on construction contract	**—**	(65)	(46,765)
Profit recognized on construction contract	**—**	(470)	(13,296)
Loss (gain) on sale of property	**—**	478	4,977
Other, net	**495**	5,734	5,630
Changes in certain current assets and liabilities —			
-Receivables	**10,448**	(23,198)	(9,717)
-Fossil fuel stock	**532**	2,604	2,738
-Materials and supplies	**(4,097)**	443	(5,345)
-Prepaid income taxes	**10,693**	4,784	16,296
-Other current assets	**(485)**	(985)	(298)
-Accounts payable	**(6,138)**	1,469	2,043
-Accrued taxes	**2,134**	(16,024)	88
-Accrued interest	**(8,102)**	53	7
-Other current liabilities	**(535)**	362	(199)
Net cash provided from operating activities	**412,379**	326,840	318,131
Investing Activities:			
Property additions	**(254,725)**	(299,602)	(137,133)
Cash paid for acquisitions	**—**	(105,042)	(194,156)
Sale of property	**25**	4,000	84
Change in construction payables, net	**(14,291)**	34,851	13,435
Payments pursuant to long-term service agreements	**(57,969)**	(41,598)	(46,120)
Other investing activities	**(1,412)**	(721)	(184)
Net cash used for investing activities	**(328,372)**	(408,112)	(364,074)
Financing Activities:			
Increase (decrease) in notes payable, net	**(90,267)**	150,840	118,948
Proceeds —			
Capital contributions	**127,241**	36,507	2,353
Senior notes	**575,000**	—	—
Other long-term debt	**—**	4,759	—
Redemptions —			
Senior notes	**(575,000)**	—	—
Other long-term debt	**(3,691)**	—	—
Premium for early debt extinguishment	**(19,375)**	—	—
Payment of common stock dividends	**(91,200)**	(107,100)	(106,100)
Other financing activities	**(3,976)**	3,318	—
Net cash provided from (used for) financing activities	**(81,268)**	88,324	15,201
Net Change in Cash and Cash Equivalents	**2,739**	7,052	(30,742)
Cash and Cash Equivalents at Beginning of Year	**14,204**	7,152	37,894
Cash and Cash Equivalents at End of Year	**$ 16,943**	$ 14,204	$ 7,152
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18,001, $12,110 and $1,624 capitalized, respectively)	**$ 74,989**	$ 63,229	$ 73,064

Income taxes (net of refunds and investment tax credits)	**(26,486)**	(6,246)	30,220
Noncash value of business exchanged in West Georgia acquisition	—	—	70,839
Noncash transactions — accrued property additions at year-end	**32,590**	46,764	15,474

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED BALANCE SHEETS
At December 31, 2011 and 2010
Southern Power Company and Subsidiary Companies 2011 Annual Report

Assets	2011	2010
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 16,943**	$ 14,204
Receivables —		
Customer accounts receivable	**59,360**	77,033
Other accounts receivable	**2,122**	1,979
Affiliated companies	**36,508**	19,673
Fossil fuel stock, at average cost	**13,038**	13,663
Materials and supplies, at average cost	**37,603**	33,934
Prepaid service agreements — current	**28,621**	41,627
Prepaid income taxes	**5,192**	53,860
Other prepaid expenses	**4,645**	4,161
Assets from risk management activities	**177**	2,160
Other current assets	**—**	19
Total current assets	**204,209**	262,313
Property, Plant, and Equipment:		
In service	**3,167,840**	3,143,919
Less accumulated provision for depreciation	**652,087**	536,107
Plant in service, net of depreciation	**2,515,753**	2,607,812
Construction work in progress	**666,280**	427,788
Total property, plant, and equipment	**3,182,033**	3,035,600
Other Property and Investments:		
Goodwill	**1,839**	1,839
Other intangible assets, net of amortization of $1,476 and $693 at December 31, 2011 and December 31, 2010, respectively	**47,644**	48,426
Total other property and investments	**49,483**	50,265
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**115,838**	69,740
Other deferred charges and assets — affiliated	**3,029**	3,275
Other deferred charges and assets — non-affiliated	**26,385**	16,541
Total deferred charges and other assets	**145,252**	89,556
Total Assets	**$3,580,977**	$3,437,734

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED BALANCE SHEETS
At December 31, 2011 and 2010
Southern Power Company and Subsidiary Companies 2011 Annual Report

Liabilities and Stockholder's Equity	2011	2010
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 555	$ —
Notes payable — affiliated	—	65,883
Notes payable — non-affiliated	179,520	203,904
Accounts payable —		
Affiliated	63,609	69,783
Other	44,321	45,985
Accrued taxes —		
Accrued income taxes	2,548	812
Other accrued taxes	2,158	2,775
Accrued interest	21,874	29,977
Liabilities from risk management activities	9,651	5,773
Other current liabilities	7,401	3,923
Total current liabilities	331,637	428,815
Long-Term Debt:		
Senior notes —		
6.25% due 2012	—	575,000
4.875% due 2015	525,000	525,000
6.375% due 2036	200,000	200,000
5.15% due 2041	575,000	—
Other long-term notes (3.25% due 2030)	513	4,759
Unamortized debt premium	2,645	—
Unamortized debt discount	(400)	(2,140)
Long-term debt	1,302,758	1,302,619
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	319,790	307,989
Deferred convertible investment tax credits	125,065	80,401
Deferred capacity revenues — affiliated	20,637	30,533
Other deferred credits and liabilities — affiliated	3,618	4,635
Other deferred credits and liabilities — non-affiliated	4,965	16,203
Total deferred credits and other liabilities	474,075	439,761
Total Liabilities	2,108,470	2,171,195
Redeemable Put Option	3,825	3,319
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	—	—
Paid-in capital	1,028,210	900,969
Retained earnings	447,301	376,270
Accumulated other comprehensive income (loss)	(6,829)	(14,019)
Total common stockholder's equity	1,468,682	1,263,220
Total Liabilities and Stockholder's Equity	$3,580,977	$3,437,734
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010, and 2009
Southern Power Company and Subsidiary Companies 2011 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2008	1	$—	$ 862,109	$ 302,309	$ (26,057)	$1,138,361
Net income	—	—	—	155,852	—	155,852
Capital contributions from parent company	—	—	2,353	—	—	2,353
Other comprehensive income (loss)	—	—	—	—	4,656	4,656
Cash dividends on common stock	—	—	—	(106,100)	—	(106,100)
Balance at December 31, 2009	1	—	864,462	352,061	(21,401)	1,195,122
Net income	—	—	—	131,309	—	131,309
Capital contributions from parent company	—	—	36,507	—	—	36,507
Other comprehensive income (loss)	—	—	—	—	7,382	7,382
Cash dividends on common stock	—	—	—	(107,100)	—	(107,100)
Balance at December 31, 2010	**1**	**—**	**900,969**	**376,270**	**(14,019)**	**1,263,220**
Net income	**—**	**—**	**—**	**162,231**	**—**	**162,231**
Capital contributions from parent company	**—**	**—**	**127,241**	**—**	**—**	**127,241**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**7,190**	**7,190**
Cash dividends on common stock	**—**	**—**	**—**	**(91,200)**	**—**	**(91,200)**
Balance at December 31, 2011	**1**	**$—**	**$1,028,210**	**$ 447,301**	**$ (6,829)**	**$1,468,682**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Southern Power Company and Subsidiary Companies 2011 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is also the parent company of four traditional operating companies, Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (APC), Georgia Power Company (GPC), Gulf Power Company (Gulf Power), and Mississippi Power Company (MPC) – are vertically integrated utilities providing electric service in four Southeastern states. The Company constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC). The Company follows generally accepted accounting principles (GAAP). The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The financial statements include the accounts of the Company and its wholly-owned subsidiaries, Southern Company – Florida LLC, Oleander Power Project, LP (Oleander), Southern Renewable Energy, Inc. (SRE), and Nacogdoches Power LLC, which own, operate, and maintain the Company's ownership interests in Plant Stanton Unit A, Plant Oleander, Plant Cimarron, and is constructing a biomass generating facility, respectively. Effective March 15, 2011, Southern Company transferred its ownership in its wholly-owned subsidiary, SRE, to the Company. SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. The transfer was accounted for by the Company as a transfer of net assets among entities under common control; therefore, the assets and liabilities of SRE were transferred from Southern Company to the Company at historical cost. The consolidated financial statements of the Company have been revised to include the financial condition and the results of operations of SRE since its inception in January 2010. All intercompany accounts and transactions have been eliminated in consolidation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for these services from SCS amounted to approximately $112.7 million in 2011, $105.2 million in 2010, and $133.0 million in 2009. Approximately $87.9 million in 2011, $89.6 million in 2010, and $83.1 million in 2009 were operations and maintenance expenses; the remainder was recorded to construction work in progress, other assets, and billings in excess of cost on construction contract. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

Total billings for all power purchase agreements (PPAs) in effect with affiliates totaled $175.9 million, $230.8 million, and $485.1 million in 2011, 2010, and 2009, respectively. Included in these billings were $20.6 million, $30.5 million, and $36.4 million of "Deferred capacity revenues – affiliated" recorded on the balance sheets at December 31, 2011, 2010, and 2009, respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company has been engaged in a strategy of acquiring assets. The Company has accounted for acquisitions from non-affiliates under the acquisition method in accordance with GAAP. Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price of each acquisition was allocated to the fair value of the identifiable assets and liabilities. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions have been expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 to the financial statements for further information.

Energy is generally sold at market-based rates and the associated revenue is recognized as the energy is delivered. Transmission revenues and other fees are recognized as incurred as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. For the year ended December 31, 2011, Florida Power & Light accounted for 14.7% of total revenues, GPC accounted for 14.0% of total revenues, and Progress Energy Carolina accounted for 8.3% of total revenues. For the year ended December 31, 2010, GPC accounted for 17.7% of total revenues, Florida Power & Light accounted for 11.4% of total revenues, and Progress Energy Carolina accounted for 8.2% of total revenues. For the year ended December 31, 2009, GPC accounted for 43.7% of total revenues, APC accounted for 6.6% of total revenues, and Sawnee Electric Membership Corporation accounted for 6.0% of total revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Convertible Investment Tax Credits

Under the American Recovery and Reinvestment Act of 2009, certain costs related to the Nacogdoches biomass plant and Plant Cimarron construction are eligible for investment tax credits (ITCs) or cash grants. The Company has elected to receive ITCs. The credits are recorded as a deferred credit, which will be amortized to income tax expense over the life of the asset, and the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period. This basis difference will reverse and be recorded to income tax expense over the useful life of the asset once placed in service. The credits received during the year are shown within operating activities in the consolidated statements of cash flows.

Property, Plant, and Equipment

The Company's depreciable property, plant, and equipment consists entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by the Company. The primary assets in property, plant, and equipment are power plants, all of which have an estimated composite depreciable life ranging from 18 to 36 years. These lives reflect a composite of the significant components (retirement units) that make up the plants. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

The amortization expense for the PPAs is as follows:

	Amortization Expense
	(in millions)
2011	$ 0.8
2012	1.8
2013	2.5
2014	2.5
2015	2.5
2016 and beyond	38.3
Total	$48.4

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Deferred Project Development Costs

The Company capitalizes project development costs once it is determined that it is probable that a specific site will be acquired and a power plant constructed. These costs include professional services, permits, and other costs directly related to the construction of a new project. These costs are generally transferred to construction work in progress upon commencement of construction. The total deferred project development costs were $9.9 million at December 31, 2011, $9.6 million at December 31, 2010, and $9.0 million at December 31, 2009.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the cost of oil, natural gas, and emissions allowances. The Company maintains oil inventory for use at Plant Dahlberg, Plant Oleander, Plant Rowan, and Plant West Georgia. The Company has contracts in place for natural gas storage. These contracts help to ensure normal operations of the Company’s natural gas generating units. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the Environmental Protection Agency are included at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in “Other” or shown separately as “Risk Management Activities”) and are measured at fair value. See Note 8 for additional information. Substantially all of the Company’s bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the “normal” scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income (OCI) until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. See Note 9 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2011.

The Company is exposed to losses related to financial instruments in the event of counterparties’ nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company’s exposure to counterparty credit risk.

Other Income and (Expense)

Other income and (expense) includes non-operating revenues and expenses. Revenues are recognized when earned and expenses are recognized when incurred.

On December 19, 2011, the Company redeemed its $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012. The loss recognized for the early redemption was $19.8 million primarily related to the payment of a make whole premium.

The Company had a long-term contract for engineering, procurement, and construction services to build a combined cycle unit for the Orlando Utilities Commission (OUC). Construction activities commenced in 2006 and were substantially completed in 2009.

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Billings and costs were recognized using the percentage of completion method. The Company utilized the cost-to-cost approach as this method is less subjective than relying on assessments of physical progress. The percentage of completion represents the percentage of the total costs incurred to the estimated total cost of the contract. Billings and costs were recognized on a net basis by applying this percentage to the total revenues and estimated costs of the contract and were recorded in other income and (expense) in the consolidated statements of income. Net profit recognized under the long-term construction contract for the OUC was $0.5 million in 2010, and $13.3 million in 2009. No profit or loss related to construction contracts was recognized in 2011.

Interest related to the construction of new facilities is capitalized in accordance with GAAP.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications of amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this accounting guidance did not result in any accounting changes for the Company.

The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS AND DIVESTITURES

Southern Renewable Energy, Inc. Acquisition

On March 15, 2011, Southern Company transferred its ownership in its wholly-owned subsidiary, SRE, to the Company. The Company's acquisition of SRE was a transfer of net assets among entities under common control; and therefore, the assets and liabilities of SRE were transferred from Southern Company to the Company at historical cost. The consolidated financial statements of the Company have been revised to include the financial condition and the results of operations of SRE since its inception in January 2010. The effect of this revision was an increase of $1.3 million in net income for the year ended December 31, 2010. There was no impact on OCI related to this change.

SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. In March 2010, SRE and Turner Renewable Energy, Inc. (TRE) partnered and, through a subsidiary, entered into an engineering, construction, and procurement agreement with First Solar, Inc. for Plant Cimarron, a 30 megawatt (MW) solar photovoltaic plant near Cimarron, New Mexico, and assumed the associated PPA. In November 2010, Plant Cimarron began commercial operation. The output from the plant is contracted under a PPA with Tri-State Generation and Transmission Association, Inc. (Tri-State). The Tri-State agreement began in December 2010 and expires in 2035. This PPA is accounted for as an operating lease.

The Company's acquisition of the interests in Plant Cimarron included cash consideration of approximately $100 million and was allocated to property, plant, and equipment. The acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant liabilities arising from contingencies as a result of this acquisition. No goodwill or other intangible assets were recorded as a result of this acquisition. Due diligence costs were expensed as incurred and were not material.

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Nacogdoches Power, LLC Acquisition

In 2009, the Company acquired all of the outstanding membership interests of Nacogdoches Power, LLC (Nacogdoches) from American Renewables LLC, the original developer of the project. Nacogdoches is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in late 2009 and the plant is expected to begin commercial operation in 2012. The total estimated cost of the project is expected to be between $470 million and $490 million. The output of the plant is contracted under a PPA with Austin Energy that begins in 2012 and expires in 2032 or until a contractual limit of $2.3 billion is reached. This PPA will be accounted for as an operating lease.

The Company's acquisition of the interests in Nacogdoches included cash consideration of approximately $50.1 million. The Nacogdoches acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant assets or liabilities arising from contingencies. No goodwill was recorded as a result of this acquisition. An intangible asset related to the assumed PPA with Austin Energy was recognized. Due diligence and transition costs for Nacogdoches were expensed as incurred and were not material. The fair value of the consideration transferred and the fair value of each major class of assets and liabilities at the acquisition date was as follows:

As of October 2009	*(in millions)*
Construction work in progress	$16.2
Other assets	0.1
Intangible assets	33.8
Total fair value of the membership interests in Nacogdoches	$50.1

West Georgia Generating Company, LLC Acquisition

In 2009, the Company acquired all of the outstanding membership interests of West Georgia Generating Company, LLC (West Georgia) from Broadway Gen Funding, LLC (Broadway), an affiliate of LS Power. West Georgia was merged into the Company and the Company now owns a 669-MW nameplate capacity generating facility consisting of four combustion turbine natural gas generating units with oil back-up. The output from two units is contracted under PPAs with the Municipal Electric Authority of Georgia (MEAG Power) and the Georgia Energy Cooperative, Inc. (GEC). The MEAG Power agreement began in 2009 and expires in 2029. The GEC agreement began in 2010 and expires in 2030.

The Company's acquisition of the interests in West Georgia was pursuant to an agreement which included the transfer of all the outstanding membership interests of DeSoto County Generating Company LLC (DeSoto) from the Company to Broadway and the payment by the Company of $144.0 million in cash consideration. The carrying values of the major classes of assets disposed of were $2.0 million in fossil fuel stock, $1.2 million in materials and supplies, $72.1 million in property, plant, and equipment, and $0.8 million in other deferred assets. The transaction was treated as a like-kind exchange for income tax purposes. The West Georgia acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant assets or liabilities arising from contingencies. The goodwill arising from the acquisition consists largely of synergies and economies of scale from combining the operations of the Company and West Georgia and is tax deductible. Due diligence and transition costs for West Georgia were expensed as incurred and were not material.

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The final fair value of the consideration transferred and the fair value of each major class of assets and liabilities at the acquisition date was as follows:

As of December 2009	*(in millions)*
Customer accounts receivable	$ 0.4
Fossil fuel stock	1.8
Materials and supplies	0.9
Property, plant, and equipment	192.4
Other assets	2.5
Goodwill	1.8
Intangible assets (PPAs)	15.3
Accounts payable	(0.3)
Total fair value of the membership interests in West Georgia	214.8
Fair value of DeSoto interests	(70.8)
Cash consideration transferred	$144.0

Revenues and expenses recognized by the Company for West Georgia operations after the closing date were not material. PPA amortization expense for 2009 was not material.

Pro Forma Information

The following unaudited pro forma financial information gives effect to the Nacogdoches acquisition, the West Georgia acquisition, and the DeSoto divestiture as if they had occurred as of the beginning of the periods presented. The pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisitions and divestiture been completed as of the dates presented nor should the information be taken as representative of any future consolidated results of operations or financial condition of the Company.

For the Twelve Months Ended December 2009	*(in millions)*
Pro forma revenues	$957.4
Pro forma net income	151.1

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

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Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million.

In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. The Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project with a nameplate capacity of 630 MWs. The unit is co-owned by the OUC (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2011, $153.8 million was recorded in plant in service with associated accumulated depreciation of $26.8 million. These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Georgia, Alabama, Mississippi, and Texas. In addition, the Company files separate company income tax returns for the States of Florida, New Mexico, and North Carolina. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2011	2010	2009
		(in millions)	
Federal —			
Current	**$61.6**	$ 4.3	$55.0
Deferred	**12.4**	46.5	19.3
	74.0	50.8	74.3
State —			
Current	**9.8**	6.5	7.7
Deferred	**(7.9)**	18.1	3.7
	1.9	24.6	11.4
Total	**$75.9**	$75.4	$85.7

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2011	2010
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	**$393.5**	$387.9
Basis difference on asset transfers	**3.3**	3.5
Other	**4.6**	5.1
Total	**401.4**	396.5
Deferred tax assets —		
Federal effect of state deferred taxes	**18.5**	20.2
Net basis difference on convertible investment tax credits	**21.8**	14.0
Basis differences on asset transfers	**3.7**	5.9
Alternative minimum tax carryforward	**1.1**	—
Other comprehensive loss on interest rate swaps	**19.1**	24.4
Levelized capacity revenues	**8.2**	12.7
Other	**11.1**	10.7
Total	**83.5**	87.9
Total deferred tax liabilities, net	**317.9**	308.6
Portion included in current income taxes	**1.9**	(0.6)
Accumulated deferred income taxes	**$319.8**	$308.0

Deferred tax liabilities are the result of property related timing differences. The transfer of the Plant McIntosh construction project to GPC in 2004 resulted in a deferred gain for federal income tax purposes. GPC is reimbursing the Company for the related tax liability balance of $3.3 million. Of this total, $0.2 million is included in the balance sheets in “Receivables — Affiliated companies” and the remainder is included in “Other deferred charges and assets — affiliated.”

Deferred tax assets consist primarily of timing differences related to net basis differences on convertible ITCs, the recognition of capacity revenues, and the deferred loss on interest rate swaps reflected in OCI. The transfer of Plants Dahlberg, Wansley, and Franklin to the Company from GPC in 2001 also resulted in a deferred gain for federal income tax purposes. The Company will reimburse GPC for the related tax asset of $4.9 million. Of this total, $1.3 million is included in the balance sheets in “Accounts payable — Affiliated” and the remainder is included in “Other deferred credits and liabilities — affiliated.”

At December 31, 2011 and December 31, 2010, the Company had a State of New Mexico net operating loss (NOL) carryforward of $88.7 million and $103.3 million, respectively. The NOL carryforward resulted in a deferred tax asset as of December 31, 2011 and December 31, 2010 of $4.0 million and $4.7 million, respectively. However, the Company has established a valuation allowance due to the remote likelihood that the full tax benefit will be realized. The valuation allowance was $3.0 million as of December 31, 2011 and $3.3 million as of December 31, 2010. During 2011, the estimated amount of NOL utilization increased resulting in a $0.3 million reduction of the valuation allowance. The NOLs expire in 2015.

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In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**0.6**	7.7	3.1
ITC basis difference	**(3.1)**	(5.6)	(1.2)
Other	**(0.7)**	(0.7)	(1.4)
Effective income tax rate	**31.8%**	36.4%	35.5%

The Company's effective tax rate decreased in 2011 primarily as a result of a decrease in state taxes. The decrease was due to a reduction in state income taxes due to a decrease in taxes apportioned to the States of Georgia and Alabama.

Convertible ITCs received in 2011 for the construction of the Nacogdoches biomass plant and Plant Cimarron were $84.7 million, which includes $42.9 million earned in 2010. The tax benefit of the basis difference reduced income tax expense by $7.3 million. See Note 1 under "Convertible Investment Tax Credits" for additional information.

Convertible ITCs received in 2010 for the construction of the Nacogdoches biomass plant were $26.4 million; the tax benefit of the basis difference reduced income tax expense by $6.9 million. The tax benefit of the basis difference related to ITCs associated with the construction of Plant Cimarron reduced tax expense by $4.6 million in 2010.

Convertible ITCs received in 2009 for the construction of the Nacogdoches biomass plant were $16.8 million; the tax benefit of the basis difference reduced income tax expense by $2.9 million.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits increased $0.3 million, resulting in a balance of $2.6 million as of December 31, 2011.

Changes during the year in unrecognized tax benefits were as follows:

	2011	2010	2009
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 2.3**	$0.1	$ 0.5
Tax positions from current periods	**0.4**	0.7	0.3
Tax positions from prior periods	**(0.1)**	1.5	(0.7)
Reductions due to settlements	**—**	—	—
Reductions due to expired statute of limitations	**—**	—	—
Balance at end of year	**$ 2.6**	$2.3	$ 0.1

The increase in unrecognized tax benefits from current periods for 2011 relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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The impact on the Company's effective tax rate, if recognized, was as follows:

	2011	2010	2009
		(in millions)	
Tax positions impacting the effective tax rate	**$0.5**	$0.6	$0.1
Tax positions not impacting the effective tax rate	**2.1**	1.7	—
Balance of unrecognized tax benefits	**$2.6**	$2.3	$0.1

The tax positions impacting the effective tax rate for 2011 primarily relate to the production activities deduction. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See "Tax Method of Accounting for Repairs" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in millions)	
Interest accrued at beginning of year	**$ —**	$—	$—
Interest accrued during the year	**0.1**	—	—
Balance at end of year	**$0.1**	$—	$—

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or state audits, could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007 through 2009. For tax years 2010 through 2012, the Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

Tax Method of Accounting for Repairs

The Company submitted a tax accounting method change for repair costs associated with its generation assets with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $6 million for the Company on a consolidated basis. The IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Other Long-Term Notes

During 2011, the Company prepaid $3.7 million on a long-term debt related to SRE.

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Senior Notes

On September 22, 2011, the Company issued $300 million aggregate principal amount of Series 2011A 5.15% Senior Notes due September 15, 2041. On November 17, 2011, the Company issued an additional $275 million of the same series of notes. Upon the completion of this offering, the aggregate principal amount of the outstanding Series 2011A 5.15% Senior Notes was $575 million. On December 19, 2011, the proceeds of the issuance were used to redeem $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012.

At December 31, 2011 and 2010, the Company had $1.3 billion of senior notes outstanding.

Bank Credit Arrangements

During 2011, the Company terminated its existing credit arrangement and entered into a $500 million committed credit facility (Facility) expiring in 2016. As of December 31, 2011, the total amount available under the Facility was $500 million.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. The Facility also contains a cross default provision that would be triggered if the Company defaulted on other indebtedness above a specified threshold. The cross default provision is restricted only to indebtedness of the Company. As of December 31, 2011, the Company was in compliance with all covenants in the Facility. The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%.

There were no borrowings outstanding under the Company's prior facility at December 31, 2010.

Proceeds from these credit arrangements may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings as of December 31, 2011 and December 31, 2010 were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	**$180**	**0.48%**	**$175**	**0.38%**	**$305**
December 31, 2010:					
Commercial paper	$204	0.41%	$169	0.40%	$259

(a) Average and maximum amounts are based upon daily balances during the period.

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

The indenture related to certain series of the Company's senior notes also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2011, the Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

7. COMMITMENTS

Expansion Program

The capital program of the Company is currently estimated to be $187 million for 2012, $419 million for 2013, and $272 million for 2014. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements (LTSAs). Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, pursuant to an agreement between SRE and TRE, on or after the fifth anniversary of the commercial operation date of Plant Cimarron, TRE may require SRE to purchase its minority interest in the plant at fair market value.

Long-Term Service Agreements

The Company has entered into LTSAs with General Electric International, Inc., Siemens Electric, Inc., and First Solar, Inc. for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Scheduled payments to the vendors, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments to the vendors under these agreements are currently estimated at $967 million over the remaining term of the LTSAs, which are currently estimated to range up to 34 years. However, the LTSAs contain various cancellation provisions at the Company's and the applicable vendor's option. In the event of cancellation prior to scheduled work being performed, the Company may be entitled to a refund of amounts paid as calculated in accordance with termination provisions of the agreements.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned maintenance are recorded as a prepayment in current assets or deferred charges and other assets on the balance sheets and are recorded as payments pursuant to long-term service agreements in the statements of cash flows. All work performed is capitalized or charged to expense as appropriate based on the nature of the work when performed; therefore, these charges are non-cash and are not reflected in the statements of cash flows.

Fuel and Purchased Power Commitments

SCS, as agent for the Company and the traditional operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities. In most cases, these contracts contain provisions for firm transportation costs, storage costs, minimum purchase levels, and other financial commitments. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on the New York Mercantile Exchange future prices at December 31, 2011. The Company has various long-term commitments for the purchase of biomass fuel for the biomass generating plant which is expected to begin operation in June 2012. The quantity of fuel to be supplied under these contracts is subject to modification based on plant operations. The amounts included in the chart below represent all noncancelable commitments.

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Southern Power Company and Subsidiary Companies 2011 Annual Report

Total estimated minimum long-term commitments at December 31, 2011 were as follows:

	Natural Gas Commitments	Biomass Fuel Commitments	Purchased Power Commitments (a)
		(in millions)	
2012	$ 399.4	$0.9	$ 49.2
2013	366.0	—	50.4
2014	272.2	—	51.6
2015	230.9	—	53.5
2016	204.1	—	38.3
2017 and beyond	172.7	—	203.4
Total	$1,645.3	$0.9	$446.4

(a) Represents contractual capacity payments.

Additional commitments for fuel will be required to supply the Company's future needs.

The Company has entered into an agreement to purchase emissions reduction credits of $1.3 million in 2012.

The Company has entered into agreements to purchase 380 MWs of power from two counterparties. Approximately 280 MWs of the commitment obligations from one counterparty will be used to serve the Company's requirements service customers. Another agreement for 100 MWs will be resold to EnergyUnited Electric Membership Corporation (EnergyUnited) at cost for the period 2012 through 2021. The purchase power commitments for the EnergyUnited agreement are $35.4 million in 2012, $36.1 million in 2013, $36.8 million in 2014, $37.6 million in 2015, $38.3 million in 2016, and $203.4 million in 2017 and beyond.

In addition, the Company has entered into an agreement to purchase power of up to 200 MWs at the discretion of the counterparty for the period 2011 through 2018. There is no contractual capacity payment required under this agreement. Additionally, for all amounts purchased under this arrangement, the Company will pay the counterparty an amount per MW which approximates the Company's cost.

Acting as an agent for all of Southern Company's traditional operating companies and the Company, SCS may enter into various types of wholesale energy and natural gas contracts. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. The credit rating of the Company is below that of the traditional operating companies; therefore, Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $0.6 million, $0.5 million, and $0.5 million for 2011, 2010, and 2009, respectively. The majority of the lease expense amounts and committed future expenditures are with a joint owner of Plant Stanton Unit A.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Operating Lease Commitments
	(in millions)
2012	$ 0.5
2013	0.5
2014	0.5
2015	0.5
2016	0.4
2017 and beyond	22.3
Total	$24.7

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8. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information. The need to use unobservable inputs would typically apply to long-term energy-related derivative contracts and generally results from the nature of the energy industry, as each participant forecasts its own power supply and demand and those of other participants, which directly impact the valuation of each unique contract.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2011, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2011:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$0.6	$—	$ 0.6
Cash equivalents	14.2	—	—	14.2
Total	$14.2	$0.6	$—	$14.8
Liabilities:				
Energy-related derivatives	$ —	$9.8	$—	$ 9.8

As of December 31, 2010, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2010:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$2.8	$—	$ 2.8
Cash equivalents	7.2	—	—	7.2
Total	$ 7.2	$2.8	$—	$10.0
Liabilities:				
Energy-related derivatives	$ —	$6.2	$—	$ 6.2

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Southern Power Company and Subsidiary Companies 2011 Annual Report

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and London Interbank Offered Rate interest rates. See Note 9 for additional information on how these derivatives are used.

As of December 31, 2011 and 2010, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2011:		*(in millions)*		
Cash equivalents:				
Money market funds	$14.2	None	Daily	Not applicable
As of December 31, 2010:				
Cash equivalents:				
Money market funds	$ 7.2	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2011	**$1,303**	**$1,397**
2010	$1,303	$1,382

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

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To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2011, the net volume of energy-related derivative contracts for power and natural gas positions for the Company, together with the longest hedge date over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Power			Gas		
Net Purchased Megawatt-hours	**Longest Hedge Date**	**Longest Non-Hedge Date**	**Net Purchased mmBtu***	**Longest Hedge Date**	**Longest Non-Hedge Date**
(in millions)			*(in millions)*		
0.1	—	2012	8.3	2012	2017

* million British thermal units

In addition to the volumes discussed in the table above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is immaterial.

For the next 12-month period ending December 31, 2012, the Company expects to reclassify $0.8 million in losses from OCI to fuel expense with respect to cash flow hedges.

Interest Rate Derivatives

The Company also enters into interest rate derivatives from time to time to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges, where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings. At December 31, 2011, there were no interest rate derivatives outstanding.

The estimated pre-tax loss that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 is $10.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments in cash flow hedges						
Energy-related derivatives:	Assets from risk management activities	**$ —**	$0.1	Liabilities from risk management activities	**$0.8**	$1.0
	Other deferred charges and assets – non-affiliated	**—**	—	Other deferred credits and liabilities – non-affiliated	**—**	—
Total derivatives designated as hedging instruments in cash flow hedges		**$ —**	$0.1		**$0.8**	$1.0
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	**$0.2**	$2.1	Liabilities from risk management activities	**$8.8**	$4.8
	Other deferred charges and assets – non-affiliated	**0.4**	0.6	Other deferred credits and liabilities – non-affiliated	**0.2**	0.4
Total derivatives not designated as hedging instruments		**$0.6**	$2.7		**$9.0**	$5.2
Total		**$0.6**	$2.8		**$9.8**	$6.2

All derivative instruments are measured at fair value. See Note 8 for additional information.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in millions)				*(in millions)*	
Energy-related derivatives	**$0.1**	$1.5	$(1.7)	Depreciation and amortization	**$ 0.4**	$ 0.4	$ 0.4
Interest rate derivatives	**—**	—	—	Interest expense, net of amounts capitalized	**(11.4)**	(10.8)	(10.0)
				Other income (expense), net	**(1.0)**	—	—
Total	**$0.1**	$1.5	$(1.7)		**$(12.0)**	$(10.4)	$ (9.6)

There was no material ineffectiveness recorded in earnings for any period presented.

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2011 Annual Report

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was as follows:

Derivatives not Designated as Hedging Instruments	**Unrealized Gain (Loss) Recognized in Income**			
		Amount		
Derivative Category	**Statements of Income Location**	**2011**	2010	2009
			(in millions)	
Energy-related derivatives:	Wholesale revenues, non-affiliates	**$ 1.8**	$(1.5)	$ 5.3
	Fuel	**(8.5)**	0.7	(6.0)
	Purchased power, non-affiliates	**0.8**	(0.7)	(4.5)
Total		**$(5.9)**	$(1.5)	$(5.2)

Included in these amounts are losses on derivative contracts reimbursable by third parties in the amount of $7.7 million, $0.8 million, and $0.4 million for 2011, 2010, and 2009, respectively, associated with hedging fuel price risk of certain PPA customers. To the extent unrealized amounts are reimbursable, there is no impact to net income.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2011, the fair value of derivative liabilities with contingent features was $2.0 million.

At December 31, 2011, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36.1 million.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade.

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Southern Power Company and Subsidiary Companies 2011 Annual Report

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income
		(in thousands)	
March 2011	**$281,787**	**$ 77,347**	**$37,743**
June 2011	**305,209**	**86,792**	**44,601**
September 2011	**362,565**	**108,708**	**56,071**
December 2011	**286,400**	**63,604**	**23,816**
March 2010	$256,488	$ 43,796	$14,724
June 2010	248,476	58,902	31,567
September 2010	356,830	111,653	62,576
December 2010	268,547	68,510	22,442

The Company's business is influenced by seasonal weather conditions.

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2007-2011
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	2011	2010	2009	2008	2007
Operating Revenues (in thousands):					
Wholesale — non-affiliates	**$ 870,607**	$ 752,772	$ 394,366	$ 667,979	$ 416,648
Wholesale — affiliates	**358,585**	370,630	544,415	638,266	547,229
Total revenues from sales of electricity	**1,229,192**	1,123,402	938,781	1,306,245	963,877
Other revenues	**6,769**	6,939	7,870	7,296	8,137
Total	**$ 1,235,961**	$ 1,130,341	$ 946,651	$ 1,313,541	$ 972,014
Net Income (in thousands)	**$ 162,231**	$ 131,309	$ 155,852	$ 144,359	$ 131,637
Cash Dividends on Common Stock (in thousands)	**$ 91,200**	$ 107,100	$ 106,100	$ 94,500	$ 89,800
Return on Average Common Equity (percent)	**11.88**	10.68	13.36	13.03	12.52
Total Assets (in thousands)	**$ 3,580,977**	$ 3,437,734	$ 3,043,053	$ 2,813,140	$ 2,768,774
Gross Property Additions/Plant Acquisitions (in thousands)	**$ 254,725**	$ 404,644	$ 331,289	$ 49,964	$ 139,198
Capitalization (in thousands):					
Common stock equity	**$ 1,468,682**	$ 1,263,220	$ 1,195,122	$ 1,138,361	$ 1,077,887
Long-term debt	**1,302,758**	1,302,619	1,297,607	1,297,353	1,297,099
Total (excluding amounts due within one year)	**$ 2,771,440**	$ 2,565,839	$ 2,492,729	$ 2,435,714	$ 2,374,986
Capitalization Ratios (percent):					
Common stock equity	**53.0**	49.2	47.9	46.7	45.4
Long-term debt	**47.0**	50.8	52.1	53.3	54.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands):					
Wholesale — non-affiliates	**16,089,875**	13,294,455	7,513,569	7,573,713	6,985,592
Wholesale — affiliates	**11,773,890**	10,494,339	12,293,585	9,402,020	10,766,003
Total	**27,863,765**	23,788,794	19,807,154	16,975,733	17,751,595
Average Revenue Per Kilowatt-Hour (cents)	**4.41**	4.72	4.74	7.69	5.43
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**7,908**	7,908	7,880	7,555	6,896
Maximum Peak-Hour Demand (megawatts):					
Winter	**3,255**	3,295	3,224	3,042	2,815
Summer	**3,589**	3,543	3,308	3,538	3,717
Annual Load Factor (percent)	**51.0**	54.0	52.6	50.0	48.2
Plant Availability (percent)	**93.9**	94.0	96.7	96.0	96.7
Source of Energy Supply (percent):					
Gas	**89.2**	88.8	84.4	75.6	70.4
Alternative (Solar)	**0.2**	—	—	—	—
Purchased power —					
From non-affiliates	**6.7**	5.5	7.9	11.3	8.8
From affiliates	**3.9**	5.7	7.7	13.1	20.8
Total	**100.0**	100.0	100.0	100.0	100.0

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PART III

Items 10, 11, 12, 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2012 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2012 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12 and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power.

Mark A. Crosswhite
President and Chief Executive Officer
Age 49
Served as Director since 2011

Allan G. Bense *(1)*
Age 60
Served as Director since 2010

Deborah H. Calder *(1)*
Age 51
Served as Director since 2010

William C. Cramer, Jr. *(1)*
Age 59
Served as Director since 2002

J. Mort O'Sullivan, III *(1)*
Age 60
Served as Director since 2010

William A. Pullum *(1)*
Age 64
Served as Director since 2001

Winston E. Scott *(1)*
Age 61
Served as Director since 2003

(1) No position other than director.

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 28, 2011) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

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Identification of executive officers of Gulf Power.

Mark A. Crosswhite
President and Chief Executive Officer
Age 49
Served as Executive Officer since 2011

Michael L. Burroughs
Vice President — Senior Production Officer
Age 51
Served as Executive Officer since 2010

P. Bernard Jacob
Vice President — Customer Operations
Age 57
Served as Executive Officer since 2003

Bentina C. Terry
Vice President — External Affairs and Corporate Services
Age 41
Served as Executive Officer since 2007

Richard S. Teel
Vice President and Chief Financial Officer
Age 41
Served as Executive Officer since 2010

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

DIRECTORS

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

Mark A. Crosswhite - President and Chief Executive Officer of Gulf Power since January 1, 2011. Mr. Crosswhite previously served as Executive Vice President of External Affairs of Alabama Power from February 2008 through December 2010 and as Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008. He also served as Vice President of SCS from March 2004 through January 2008.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming and represented the Bay County area in the Florida House of Representatives beginning in 1998 and served as Speaker of the House from 2004 through 2006. Mr. Bense has also served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011.

Deborah H. Calder - Senior Vice President for Navy Federal Credit Union since June 2008. Since September 2007, Ms. Calder has directed the day-to-day operations of more than 1,400 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 19 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida, Georgia, and Alabama. Mr. Cramer has been an authorized Chevrolet dealer since 1978. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

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J. Mort O'Sullivan, III - Managing Partner of Warren Averett O'Sullivan Creel, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor.

William A. Pullum - President and Director of Bill Pullum Realty, Inc., Navarre, Florida. Mr. Pullum is also a real estate developer.

Winston E. Scott - Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida since August 2008. He previously served as Vice President and Deputy General Manager, Engineering and Science Contract Group at Jacobs Engineering, Houston, Texas, from September 2006 through July 2008. Mr. Scott's experience also included serving as a pilot in the U.S. Navy, as an astronaut with the National Aeronautic and Space Administration, and as executive director of the Florida Space Authority.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010 and as Assistant to the Chief Production Officer of SCS Generation from May 2006 to August 2007.

P. Bernard Jacob - Vice President of Customer Operations since 2007. He previously served as Vice President of External Affairs and Corporate Services from 2003 to 2007.

Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010.

Bentina C. Terry - Vice President of External Affairs and Corporate Services since 2007.

Involvement in certain legal proceedings. None.

Promoters and Certain Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com . The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com . The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

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ITEM 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2011, as well as each of Gulf Power's other three most highly compensated executive officers serving at the end of the year. Collectively, these officers are referred to as the named executive officers.

Mark A. Crosswhite	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
Paul B. Jacob	Vice President
Bentina C. Terry	Vice President

Executive Summary

Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to Gulf Power's named executive officers for 2011.

	Salary ($)(1)	% of Total	Short-Term Performance Pay ($)(1)	% of Total	Long-Term Performance Pay ($)(1)	% of Total
M. A. Crosswhite	395,937	34	256,507	22	519,368	44
R. S. Teel	225,993	48	109,378	23	136,276	29
M. L. Burroughs	180,684	52	93,144	27	72,739	21
P. B. Jacob	249,188	48	120,319	23	149,894	29
B. C. Terry	250,194	48	121,113	23	150,902	29

(1) Salary is the actual amount paid in 2011, Short-Term Performance Pay is the actual amount earned in 2011 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2011. See the Summary Compensation Table herein for the amounts of all elements of reportable compensation described in this CD&A.

Business unit financial, operational, and Southern Company earnings per share goal results for 2011 are shown below.

Business unit financial goals:	0% of Target
Operational goals:	165% of Target
Southern Company earnings per share:	156% of Target

These levels of achievement for operational goals and Southern Company earnings per share resulted in actual payouts that exceeded targets. Southern Company's total shareholder return has been:

1-year: 26.9%
3-year: 13.4%
5-year: 9.9%

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Compensation and Benefit Beliefs

The compensation and benefit program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power's executive compensation program should:

- be competitive with the companies in Gulf Power's industry;
- motivate and reward achievement of Gulf Power's goals;
- be aligned with the interests of Southern Company's stockholders and Gulf Power's customers; and
- not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power's and Southern Company's business goals. Gulf Power believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for Southern Company's stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power's operational and financial goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by Southern Company's earnings per share performance. Long-term performance pay is tied to Southern Company stockholder value with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance share units, which reward total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention of an independent consultant, Pay Governance LLC, that provides no other services to Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited perquisites and no income tax gross-ups for the Chief Executive Officer, except on relocation-related benefits.
- "No-hedging" provision in Southern Company's inside trading policy that is applicable to all employees.
- Strong stock ownership requirements that are being met by all named executive officers.

ESTABLISHING EXECUTIVE COMPENSATION

The Compensation Committee establishes the executive compensation program. In doing so, the Compensation Committee uses information from others, principally its independent compensation consultant, Pay Governance LLC. The Compensation Committee also relies on information from Southern Company's Human Resources staff and, for individual executive officer performance, from Gulf Power's and Southern Company's Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

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Review of Compensation and Benefits

In 2011, Southern Company conducted an extensive review of its compensation and benefit program. Numerous focus groups with employees at all levels were conducted, and outside consultants were retained to review all aspects of the program.

The review was conducted with the support of, and input from, the Compensation Committee. The findings of the review confirmed that Southern Company's compensation and benefit program, including the appropriate payout levels under performance-based pay components, is competitive and consistent with industry peers. These findings were reviewed with the Compensation Committee.

GUIDING PRINCIPLES AND POLICIES

Southern Company, through a single compensation program for all officers of its subsidiaries, drives and rewards both Southern Company financial performance and individual business unit performance. This executive compensation program is based on a philosophy that total executive compensation must be competitive with the companies in the industry, must be tied to and motivate executives to meet short- and long-term performance goals, must foster and encourage alignment of executive interests with the interests of Southern Company's stockholders and Gulf Power's customers, and must not encourage excessive risk-taking. The program generally is designed to motivate all employees, including executives, to achieve operational excellence and financial goals while maintaining a safe work environment.

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Gulf Power's business unit performance, which includes return on equity (ROE), operational performance compared to target performance levels established early in the year, and Southern Company's actual earnings per share (EPS) determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Southern Company common stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company's total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control.

The pay-for-performance principles apply not only to the named executive officers, but to hundreds of Gulf Power employees. The Performance Pay Program covers almost all of the approximately 1,400 Gulf Power employees. Stock options and performance shares are granted to approximately 100 employees. These programs engage employees, which ultimately is good not only for them, but also for Gulf Power's customers and Southern Company's stockholders.

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OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The executive compensation program has several components, each of which plays a different role. The chart below discusses the intended role of each material pay component, what it rewards, and why it is used. Following the chart is additional information that describes how 2011 pay decisions were made.

Pay Element	Intended Role and What the Element Rewards	Why the Element Is Used
Base Salary	Base salary is pay for competence in the executive role, with a focus on scope of responsibilities.	Market practice. Provides a threshold level of cash compensation for job performance.
Annual Performance-Based Compensation: Performance Pay Program	The Performance Pay Program rewards achievement of business unit operational and financial goals and EPS.	Market practice. Focuses attention on achievement of short-term goals that ultimately work to fulfill the mission to customers and lead to increased stockholder value in the long term.
Long-Term Performance-Based Compensation: Stock Options	Stock options reward price increases in Common Stock over the market price on the date of grant, over a 10-year term.	Market practice. Performance-based compensation. Aligns recipients' interests with those of Southern Company's stockholders.
Long-Term Performance-Based Compensation: Performance Shares	Performance shares provide equity compensation dependent on Southern Company's three-year total shareholder return versus industry peers.	Market practice. Performance-based compensation. Aligns recipients' interests with Southern Company's stockholders' interests since payouts are dependent on the returns realized by Southern Company's stockholders versus those of industry peers.
Retirement Benefits	Executives participate in employee benefit plans available to all employees of Gulf Power, including a 401(k) savings plan and the funded Southern Company Pension Plan (Pension Plan). The Southern Company Deferred Compensation Plan provides the opportunity to defer to future years up to 50% of base salary and all or part of performance-based non-equity compensation in either a prime interest rate or Common Stock account. The Supplemental Benefit Plan counts pay, including deferred salary, that is ineligible to be counted under the Pension Plan and the 401(k) plan due to Internal Revenue Service rules. The Supplemental Executive Retirement Plan counts annual performance-based pay above 15% of base salary for pension purposes. To retain mid-career hires, supplemental retirement agreements give pension credit for	Represents an important component of competitive market-based compensation in both the peer group and generally. Permitting compensation deferral is a cost-effective method of providing additional cash flow to Gulf Power while enhancing the retirement savings of executives. The purpose of these supplemental plans is to eliminate the effect of tax limitations on the payment of retirement benefits.

years of relevant experience prior to employment with Gulf Power or its affiliates.

Pay Element	Intended Role and What the Element Rewards	Why the Element Is Used
Perquisites and Other Personal Benefits	Personal financial planning maximizes the perceived value of the executive compensation program to executives and allows them to focus on operations. Limited personal use by the Chief Executive Officer of corporate-owned aircraft associated with geographic relocation. Relocation benefits cover the costs associated with geographic relocations at the request of Gulf Power. For the President and Chief Executive Officer, tax gross-ups are not provided on any perquisites except relocation benefits.	These limited perquisites represent an effective, low-cost means to retain key talent.
Severance Arrangements	Change-in-control plans provide severance pay, accelerated vesting, and payment of short- and long-term performance-based compensation upon a change in control of Gulf Power coupled with involuntary termination not for cause or a voluntary termination for "Good Reason."	Market practice. Providing protections to executives upon a change in control minimizes disruption during a pending or anticipated change in control. Payment and vesting occur only upon the occurrence of both an actual change in control and loss of the executive's position.

MARKET DATA

For the named executive officers, the Compensation Committee reviews compensation data from large, publicly-owned electric and gas utilities. The data was developed and analyzed by Pay Governance LLC, the independent compensation consultant retained by the Compensation Committee. The companies included each year in the primary peer group are those whose data is available through the consultant's database. Those companies are drawn from this list of primarily regulated utilities of $2 billion in revenues and up.

AGL Resources Inc.	Energy Future Holdings Corp.	PG&E Corporation
Allegheny Energy, Inc.	Entergy Corporation	Pinnacle West Capital Corporation
Alliant Energy Corporation	Exelon Corporation	PPL Corporation
Ameren Corporation	FirstEnergy Corp.	Progress Energy, Inc.
American Electric Power Company, Inc.	Hawaiian Electric Industries, Inc.	Public Service Enterprise Group Incorporated
Atmos Energy Corporation	Integrys Energy Group, Inc.	Puget Energy, Inc.
Calpine Corporation	LG&E and KU Energy LLC	Salt River Project
CenterPoint Energy, Inc.	MDU Resources Group, Inc.	SCANA Corporation
CMS Energy Corporation	Mirant Corporation	Sempra Energy
Consolidated Edison, Inc.	New York Power Authority	Spectra Energy Corp.
Constellation Energy Group, Inc.	NextEra Energy, Inc.	TECO Energy, Inc.
CPS Energy	Nicor Inc.	Tennessee Valley Authority
Dominion Resources, Inc.	Northeast Utilities	The Williams Companies, Inc.
DTE Energy Company	NRG Energy, Inc.	UGI Corporation
Duke Energy Corporation	NSTAR	Vectren Corporation
Dynegy Inc.	NV Energy, Inc.	Wisconsin Energy Corporation
Edison International	OGE Energy Corp.	Xcel Energy Inc.
El Paso Corporation	Pepco Holdings, Inc.	

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Southern Company is one of the largest utility holding companies in the United States based on revenues and market capitalization, and its largest business units are some of the largest in the industry as well. For that reason, the consultant size-adjusts the survey market data in order to fit it to the scope of the business.

In using this market data, market is defined as the size-adjusted 50th percentile (median) of the survey data, with a focus on pay opportunities at target performance (rather than actual plan payouts). Market data for the chief executive officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed. Based on that data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, annual performance-based compensation at a target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's and Southern Company's performance for the year or period.

A specified weight was not targeted for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2011 compensation amounts. Total target compensation opportunities for senior management as a group are managed to be at the median of the market for companies of similar size in the electric utility industry. The total target compensation opportunity established in early 2011 for each named executive officer is shown below.

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
M. A. Crosswhite	399,543	239,726	519,368	1,158,637
R. S. Teel	227,161	102,222	136,276	465,659
M. L. Burroughs	181,922	72,769	72,739	327,430
P. B. Jacob	249,884	112,448	149,894	512,226
B. C. Terry	251,533	113,190	150,902	515,625

The salary levels shown above were not effective until March 1, 2011. Therefore, the salary amounts reported in the Summary Compensation Table are lower because that table reports actual amounts paid in 2011.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $3.25 per option and performance shares at $35.97 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted were 40% and 60%, respectively, of the long-term value shown above.

As discussed above, the Compensation Committee targets total target compensation opportunities for senior management as a group at market. Therefore, some executives may be paid somewhat above and others somewhat below market. This practice allows for minor differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. The average total target compensation opportunities for the named executive officers for 2011 were at the median of the market data described above. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, slight differences are not considered to be material and the compensation program is believed to be market-appropriate. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data.

In 2010, Pay Governance LLC, the Compensation Committee's independent consultant, analyzed the level of actual payouts, for 2009 performance, under the annual Performance Pay Program to the named executive officers relative to performance versus peer companies to provide a check on the goal-setting process, including goal levels and

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associated performance-based pay opportunities. The findings from the analysis were used in establishing performance goals and the associated range of payouts for goal achievement for 2011. That analysis was updated by Pay Governance LLC in 2011 for 2010 performance, and those findings were used in establishing goals for 2012.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2011 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2011.

With the exception of Mr. Crosswhite, the named executive officers are each within a position level with a base salary range that is established under the direction of the Compensation Committee using the market data described above. The actual base salary levels set for each of these named executive officers are within the pre-established salary ranges. Also considered in recommending the specific base salary level for each named executive officer is the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the results of operations in prior years. Mr. Crosswhite's total target compensation opportunity, including base salary, is not within a position level band. It is set directly by the Compensation Committee using the above-described market data for specific positions similar in scope and responsibility in the market peer companies listed above.

Base salaries for Ms. Terry and Messrs. Jacob and Teel were recommended by Mr. Crosswhite to Southern Company's Chief Executive Officer. The base salary for Mr. Burroughs, who serves as an executive officer of Gulf Power and of Southern Company's generation business unit (Southern Company Generation), was recommended by Southern Company's Chief Operating Officer, who is the senior executive of Southern Company Generation, with input from Mr. Crosswhite. Mr. Crosswhite also is an executive officer of Southern Company. His base salary was recommended by Southern Company's Chief Executive Officer to the Compensation Committee and was influenced by the above-described market data. The base salary for Mr. Crosswhite was approved by the Compensation Committee. The base salaries of the other named executive officers were approved by Southern Company's Chief Executive Officer.

2011 Performance-Based Compensation

This section describes the performance-based compensation program in 2011.

Achieving Operational and Financial Goals — The Guiding Principle for Performance-Based Compensation

The number one priority is to continue to provide Gulf Power's customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Gulf Power and Southern Company's stockholders in the short and long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2011, Gulf Power strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices; and
- Meeting energy demand with the best economic and environmental choices.

In 2011, Gulf Power also focused on and rewarded:

- Southern Company earnings per share (EPS) growth;
- Gulf Power ROE – target performance level in the top quartile of comparable electric utilities;
- Southern Company dividend growth;

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- Long-term, risk-adjusted Southern Company total shareholder return; and
- Financial integrity — an attractive risk-adjusted return, sound financial policy, and a stable "A" credit rating.

The performance-based compensation program is designed to encourage achievement of these goals.

The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommended to the Compensation Committee program design and award amounts for senior management, including the named executive officers.

2011 Annual Performance Pay Program

Program Design

The Performance Pay Program is Gulf Power's annual performance-based compensation program. Almost all employees of Gulf Power, including the named executive officers, are participants, for a total of approximately 1,400 participants.

The performance goals are set at the beginning of each year by the Compensation Committee.

- For Southern Company's traditional operating companies, including Gulf Power, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, and culture.
- Southern Company EPS is defined as earnings from continuing operations divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.
- For Southern Company's traditional operating companies, including Gulf Power, the business unit financial performance goal is ROE, which is defined as the traditional operating company's net income divided by average equity for the year.
- For Southern Company Generation, the operational goals are aggregated for all of the traditional operating companies and Southern Nuclear. The business unit financial goal is based 90% on the aggregate ROE goal performance for the traditional operating companies and 10% on Southern Power net income.

For all of the named executive officers, except for Mr. Burroughs, the Annual Performance Pay Program payout attributable to business unit performance is calculated using Gulf Power's ROE and operational goals. For Mr. Burroughs, it is based 60% on Gulf Power's results and 40% on Southern Company Generation's results.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial goals, such adjustments could include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the earnings goal was established and of sufficient magnitude to warrant recognition. No adjustments were made in 2011.

Under the terms of the program, no payout can be made if Southern Company's current earnings are not sufficient to fund the Common Stock dividend at the same level or higher than the prior year.

Goal Details

Operational Goals:

Customer Satisfaction — Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking as well as a ranking for each customer segment: residential, commercial, and industrial.

Reliability — Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.

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Availability — Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.

Safety — Southern Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.

Culture — The culture goal seeks to improve Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.

The ranges of performance levels established for the primary operational goals are detailed below.

Level of Performance	**Customer Satisfaction**	**Reliability**	**Availability**	**Safety**	**Culture**
Maximum	Top quartile for all customer segments and overall	Significantly exceed target	Industry best	Greater than top 20th percentile and Southern Company best	Significant improvement
Target	Top quartile overall	Historical Southern Company average	Top quartile	Top 40th percentile	Improvement
Threshold	2nd quartile overall	Significantly below target	2nd quartile	Top 60th percentile	Significantly below expectations

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. Collectively, customer satisfaction, reliability, and availability are weighted 60% and safety and culture are weighted 20% each. If goal achievement is below threshold, there is no payout associated with the applicable goal.

Southern Company EPS and Business Unit Financial Performance:

The range of Southern Company EPS, business unit ROE, and Southern Power net income goals for 2011 is shown below. ROE goals vary from the allowed retail ROE range due to state regulatory accounting requirements, wholesale activities, other non-jurisdictional revenues and expenses, and other activities not subject to state regulation.

Level of Performance	**EPS ($)**	**Business Unit ROE (%)**	**Southern Power Net Income ($) (millions)**
Maximum	2.65	14.0	150
Target	2.52	12.0	130
Threshold	2.39	10.0	110

For 2011, the Compensation Committee established a minimum EPS performance threshold that must be achieved. If Southern Company EPS was less than $2.27 (90% of target), not only would there have been no payout associated with EPS performance, but overall payouts under the Performance Pay Program would have been reduced by 10% of target.

In setting the goals for pay purposes, the Compensation Committee relies on information from the Finance and Nuclear/Operations Committees of the Southern Company Board of Directors.

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2011 Achievement

Each named executive officer had a target Performance Pay Program opportunity, based on his or her position, set by the Compensation Committee at the beginning of 2011. Targets are set as a percentage of base salary. Mr. Crosswhite's target was set at 60%, Ms. Terry's and Messrs. Jacob's and Teel's targets were set at 45%, and Mr. Burroughs' target was set at 40%. Actual payouts were determined by adding the payouts derived from Southern Company EPS and applicable operational and business unit financial performance goal achievement for 2011 and dividing by three. Southern Company EPS exceeded the minimum threshold established and therefore payouts were not affected. Actual 2011 goal achievement is shown in the following tables.

Operational Goal Results:

Gulf Power

Goal	Achievement Percentage
Customer Satisfaction	133
Reliability	200
Availability	200
Safety	200
Culture	127

Southern Company Generation

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	197
Availability	200
Safety	200
Culture	151
Southern Nuclear	153

Overall, the levels of achievement shown above resulted in an operational goal performance factor of 165% for Gulf Power and 187% for Southern Company Generation.

Financial Goal Results:

Goal	Result	Achievement Percentage
Southern Company EPS	$2.57	156
Gulf Power ROE	9.55%	0
Aggregate ROE	12.6%	131
Southern Power net income	$162 million	200

The aggregate ROE and Southern Power net income achievement resulted in a business unit financial achievement percentage for Southern Company Generation of 138%.

A total performance factor is determined by adding Southern Company EPS and applicable business unit financial and operational goal results and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity, as described above, to determine the payout for each named executive officer. The table below shows the pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

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	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
M. A. Crosswhite	239,726	107	256,507
R. S. Teel	102,222	107	109,378
M. L. Burroughs	72,769	128	93,144
P. B. Jacob	112,448	107	120,319
B. C. Terry	113,190	107	121,113

Long-Term Performance-Based Compensation

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company's stockholders. The long-term awards provide an incentive to grow Southern Company's stockholder value.

Southern Company stock options represent 40% of the long-term performance target value and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Stock options only generate value if the price of the stock appreciates after the grant date and performance shares reward employees based on total shareholder return relative to industry peers, as well as stock price.

The following table shows the grant date fair value of the long-term performance-based awards in total and each component awarded in 2011.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
M. A. Crosswhite	207,760	311,608	519,368
R. S. Teel	54,516	81,760	136,276
M. L. Burroughs	29,107	43,632	72,739
P. B. Jacob	59,969	89,925	149,894
B. C. Terry	60,366	90,536	150,902

Stock Options

Stock options granted have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. For the grant made to Mr. Crosswhite in 2011, unvested options are forfeited if he retires and accepts a position with a peer company within two years of retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2011, the Black-Scholes value on the grant date was $3.25 per stock option.

Performance Shares

Performance shares are denominated in units, meaning no actual shares are issued at the grant date. A grant date fair value per unit is determined. For the grant made in 2011, that value per unit was $35.97. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock. At the end of the three-year performance period, the number of units will be adjusted up or down (zero to 200%) based on Southern Company's total shareholder return relative to

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that of its peers in the Philadelphia Utility Index and the custom peer group. The companies in the custom peer group are those that are believed to be most similar to Southern Company in both business model and investors. The Philadelphia Utility Index was chosen because it is a published index and, because it includes a larger number of peer companies, it can mitigate volatility in results over time, providing an appropriate level of balance. The peer groups vary from the Market Data peer group (as listed on page III-8) due to the timing and criteria of the peer selection process; however, there is significant overlap. The results of the two peer groups will be averaged. The number of performance share units earned will be paid in Common Stock at the end of the three-year performance period. No dividends or dividend equivalents will be paid or earned on the performance share units.

The companies in the Philadelphia Utility Index on the grant date are listed below.

Ameren Corporation	Exelon Corporation
American Electric Power Company, Inc.	FirstEnergy Corp.
CenterPoint Energy, Inc.	NextEra Energy, Inc.
Consolidated Edison, Inc.	Northeast Utilities
Constellation Energy Group, Inc.	PG&E Corporation
Dominion Resources, Inc.	Progress Energy, Inc.
DTE Energy Company	Public Service Enterprise Group Incorporated
Duke Energy Corporation	The AES Corporation
Edison International	Xcel Energy Inc.
Entergy Corporation	

The companies in the custom peer group are listed below.

American Electric Power Company, Inc.	PG&E Corporation
Consolidated Edison, Inc.	Progress Energy, Inc.
Duke Energy Corporation	Wisconsin Energy Corporation
Northeast Utilities	Xcel Energy Inc.
NSTAR	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2011-2013 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Groups	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher (Maximum)	200
50th percentile (Target)	100
10th percentile (Threshold)	0

Performance shares are not earned until the end of the three-year performance period. A participant who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

More information about stock options and performance shares is contained in the Grants of Plan-Based Awards table and the accompanying information.

Performance Dividends

The Compensation Committee terminated the Performance Dividend Program in 2010. The value of performance dividends represented a significant portion of long-term performance-based compensation that was awarded prior to 2010. At target performance levels, performance dividends represented up to 65% of the total long-term value

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granted over the 10-year term of stock options. Therefore, because performance dividends were awarded for years prior to 2010, in fairness to participants, the outstanding performance dividend awards were not cancelled. The Compensation Committee approved a three-year transition period, beginning with the 2007 through 2010 performance-measurement period, to continue to pay performance dividends, if earned, on stock options that were granted prior to 2010. The grant of performance shares, described above, replaced performance dividend awards beginning in 2010. Therefore, performance dividends were paid on stock options granted prior to 2010 that were outstanding at the end of the four-year performance-measurement period that ended December 31, 2011, as reported in the Summary Compensation Table, and will be paid for one more uncompleted four-year performance-measurement period, 2009 through 2012. Because performance dividends granted prior to 2008 were paid on all stock options held at the end of each performance-measurement period, absent the exercise of stock options, the number of stock options upon which performance dividends were paid increased over the four-year performance-measurement period. During the transition period, the outstanding performance dividends are paid only on stock options granted prior to 2010. Because performance shares are earned at the end of a three-year performance period, both the last award of performance dividends and the first award of performance shares will be earned at the end of 2012.

Performance dividends can range from 0% to 100% of the Common Stock dividend paid during the year per eligible stock option held at the end of the performance-measurement period. Actual payout will depend on Southern Company's total shareholder return over a four-year performance-measurement period compared to a group of other electric and gas utility companies. The peer group was determined at the beginning of each four-year performance-measurement period. The peer group for performance dividends was set by the Compensation Committee at the beginning of the four-year performance-measurement period.

Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each company's common stock at the beginning of each of 16 quarters. In the final year of the performance-measurement period, Southern Company's ranking in the peer group is determined at the end of each quarter and the percentile ranking is multiplied by the actual Common Stock dividend paid in that quarter. To determine the total payout per stock option held at the end of the performance-measurement period, the four quarterly amounts earned are added together.

No performance dividends are paid if Southern Company's earnings are not sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

2011 Payout

The peer group used to determine the 2011 payout for the 2008-2011 performance-measurement period consisted of utilities with revenues of $1.2 billion or more with regulated revenues of 60% or more. Those companies are listed below.

Allegheny Energy, Inc.	Entergy Corporation	Puget Energy, Inc.
Alliant Energy Corporation	Exelon Corporation	SCANA Corporation
Ameren Corporation	Hawaiian Electric Company, Inc.	TECO Energy, Inc.
American Electric Power Company, Inc.	NextEra Energy, Inc.	UIL Holdings Corporation
Avista Corporation	NiSource Inc.	Unisource Energy Corporation
CMS Energy Corporation	Northeast Utilities	Vectren Corporation
Consolidated Edison, Inc.	NSTAR	Westar Energy, Inc.
Dominion Resources, Inc.	NV Energy, Inc.	Wisconsin Energy Corporation
DPL Inc.	Pepco Holdings, Inc.	Xcel Energy Inc.
DTE Energy Corporation	PG&E Corporation	
Duke Energy Corporation	Pinnacle West Capital Corporation	
	Progress Energy, Inc.	

The scale below determined the percentage of each quarter's dividend paid in the last year of the performance-measurement period to be paid on each eligible stock option held at December 31, 2011, based on performance during the 2008-2011 performance-measurement period. Payout for performance between points was interpolated on a straight-line basis.

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Performance vs. Peer Group	Payout (% of Each Quarterly Dividend Paid)
90th percentile or higher	100
50th percentile (Target)	50
10th percentile or lower	0

Southern Company's total shareholder return performance, as measured at the end of each quarter of the final year of the four-year performance-measurement period ending with 2011, was the 38 th , 41 st , 69 th , and 71 st percentile, respectively, resulting in a total payout of 112% of the target level (56.1% of the full year's Common Stock dividend), or $1.05. This amount was multiplied by each named executive officer's eligible outstanding stock options as of December 31, 2011 to calculate the payout under the program. The amount paid is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table.

Timing of Performance-Based Compensation

As discussed above, the 2011 annual Performance Pay Program goals and the Southern Company total shareholder return goals applicable to performance shares were established at the February 2011 Compensation Committee meeting. Annual stock option grants also were made at that meeting. The establishment of performance-based compensation goals and the granting of stock options were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2011 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Retirement and Severance Benefits

As mentioned above, certain post-employment compensation are provided to employees, including the named executive officers.

Retirement Benefits

Generally, all full-time employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Unfunded benefits also are provided that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. (These plans are the Supplemental Benefit Plan and the Supplemental Executive Retirement Plan that are described in the chart on page III-7 of this CD&A.) See the Pension Benefits table and accompanying information for more pension-related benefits information.

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has a supplemental retirement agreement (SRA) with both Ms. Terry and Mr. Crosswhite. Prior to their employment, Ms. Terry and Mr. Crosswhite provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years and Mr. Crosswhite's provides an additional 15 years of benefits. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf Power for 10 years from the effective date of the SRA, before vesting in the benefits. Mr. Crosswhite is vested in the benefits. These agreements provide a benefit which recognizes the expertise both brought to Gulf Power and they provide a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond.

Gulf Power also provides the Deferred Compensation Plan which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and the information accompanying it for more information about the Deferred Compensation Plan.

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Change-in-Control Protections

The Compensation Committee initially approved the change-in-control protection program in 1998 to provide certain compensatory protections to employees, including the named executive officers, upon a change in control and thereby allow them to negotiate aggressively with a prospective purchaser.

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; *i.e.*, there must be both a change in control and a termination of employment.

In 2011, the Compensation Committee made changes to the program that were effective immediately. Notably, the following changes were made:

- Reduction of severance payment level from three times base salary plus target Performance Pay Program opportunity to two times that amount for all executive officers of Southern Company, including Mr. Crosswhite, except for the Chief Executive Officer of Southern Company. (In 2009, the Compensation Committee lowered the severance payment level for all other officers from two times base salary plus target Performance Pay Program opportunity to one times that amount.)
- Elimination of excise tax gross-up for all participants, including all of the named executive officers.

After the changes made in 2009 and 2011, Mr. Crosswhite's severance level is two times base salary plus target Performance Pay Program opportunity and it is one times that amount for all other named executive officers of Gulf Power.

More information about severance arrangements is included in the section entitled Potential Payments upon Termination or Change in Control.

Perquisites

Gulf Power provides limited perquisites to its named executive officers. The perquisites provided in 2011, including amounts, are described in detail in the information accompanying the Summary Compensation Table.

Executive Stock Ownership Requirements

Officers of Southern Company and its subsidiaries that are in a position of vice president or above are subject to stock ownership requirements. All of Gulf Power's named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership.

The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	**Multiple of Salary Counting 1/3 of Vested Options**
M. A. Crosswhite	3 Times	6 Times
R. S. Teel	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
P. B. Jacob	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have five years from the date of their election to meet the applicable ownership requirement and newly-promoted officers have five years from the date of their promotion to meet the increased ownership requirements.

Policy on Recovery of Awards

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer will reimburse Gulf Power the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

Company Policy Regarding Hedging the Economic Risk of Stock Ownership

Southern Company's policy is that employees and outside directors will not trade Southern Company options on the options market and will not engage in short sales.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2011. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

J. Neal Purcell, Chair
Henry A. Clark, III
H. William Habermeyer, Jr.
Donald M. James

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SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2009, 2010, and 2011 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
M.A. Crosswhite President, Chief Executive Officer, and Director	2011	395,937	38,791	311,608	207,760	384,016	366,993	480,990	2,186,095
R. S. Teel	2011	225,993	0	81,760	54,516	156,624	72,473	14,773	606,139
Vice President and Chief Financial Officer	2010	205,540	22,056	47,244	31,508	171,316	50,082	448,620	976,366
M. L. Burroughs	2011	180,684	0	43,632	29,107	102,255	135,314	49,366	540,358
Vice President	2010	150,745	24,612	12,082	8,073	95,255	94,324	220,820	605,911
P. B. Jacob	2011	249,188	0	89,925	59,969	159,207	233,428	15,714	807,431
Vice President	2010	239,444	0	85,810	57,217	172,892	176,201	19,021	750,585
	2009	239,205	0	0	50,359	146,661	199,239	23,487	658,951
B. C. Terry	2011	250,194	0	90,536	60,366	182,994	122,604	15,957	722,651
Vice President	2010	237,466	0	85,087	56,742	183,929	259,023	22,542	844,789
	2009	237,219	0	0	49,939	134,728	48,437	25,427	495,750

Column (a)

Mr. Crosswhite was not an executive officer of Gulf Power prior to 2011 and Messrs. Burroughs and Teel were not executive officers prior to 2010.

Column (d)

The amount shown for 2011 for Mr. Crosswhite is a geographic relocation incentive that was paid in connection with his relocation. The relocation incentive equaled 10% of salary rate as of the date of relocation.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2011. Rather, as required by applicable rules of the Securities and Exchange Commission (SEC), this column reports the aggregate grant date fair value of performance shares granted in 2011. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2013. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2011 to Ms. Terry and Messrs. Crosswhite, Teel, Burroughs, and Jacob, assuming the highest level of performance is achieved, is $181,073, $623,216, $163,520, $87,263, and $179,850, respectively (200% of the amount shown in the table). See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

As described in detail in the CD&A, in 2010 the first awards of performance shares were made and no further awards of performance dividends were made. In 2009, stock options were awarded (as shown in column (f)) with associated performance dividends, as described in the CD&A. The grant date value of performance dividends was

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reported in the CD&A and the threshold, target, and maximum payouts of performance dividends based on certain assumptions were reported in the Grants of Plan-Based Awards table. However, because of disclosure requirements, no grant date value for performance dividend awards was disclosed in the Summary Compensation Table in the year granted. Instead, the actual cash payouts in the applicable year with respect to all outstanding performance dividends were reported as Non-Equity Incentive Plan Compensation in column (g). The grant date value for performance dividends, as reported in the CD&A for 2009, is as follows:

	Grant Date Value ($)
M. A. Crosswhite	132,640
R. S. Teel	48,142
M. L. Burroughs	12,114
P. B. Jacob	87,848
B. C. Terry	87,116

Column (f)

This column reports the aggregate grant date fair value of stock options. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the aggregate of the payouts under the annual Performance Pay Program and under the Performance Dividend Program. The amount reported for annual performance-based compensation is for the one-year performance period ended December 31, 2011. The amount reported for performance dividends is the amount earned at the end of the four-year performance-measurement period of January 1, 2008 through December 31, 2011. These awards were granted by the Compensation Committee in 2008 and are paid on stock options granted prior to 2010 that were outstanding at the end of 2011. As described in the CD&A, the Performance Dividend Program was eliminated by the Compensation Committee in 2010 and replaced with performance shares. This payout reported in column (g) is the second payout in the three-year transition period as described in the CD&A. The Performance Pay Program, the Performance Dividend Program, and performance shares are described in detail in the CD&A.

The amounts paid under each program to the named executive officers are shown below.

	Annual Performance-Based Compensation ($)	Performance Dividends ($)	Total ($)
M. A. Crosswhite	256,507	127,509	384,016
R. S. Teel	109,378	47,246	156,624
M. L. Burroughs	93,144	9,111	102,255
P. B. Jacob	120,319	38,888	159,207
B. C. Terry	121,113	61,881	182,994

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31, 2009, 2010, and 2011. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any other Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

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For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2011, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2010 and December 31, 2011 follow:

- Discount rate for the Pension Plan was decreased to 5.0% as of December 31, 2011 from 5.55% as of December 31, 2010
- Discount rate for the supplemental pension plans was decreased to 4.65% as of December 31, 2011 from 5.05% as of December 31, 2010

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; tax reimbursements on certain perquisites; the contributions in 2011 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Code; and contributions in 2011 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported are itemized below.

	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
M. A. Crosswhite	362,596	98,600	12,096	7,698	480,990
R. S. Teel	4,059	85	10,629	0	14,773
M. L. Burroughs	37,872	2,279	9,215	0	49,366
P. B. Jacob	4,656	239	10,606	214	15,714
B. C. Terry	4,917	181	10,594	265	15,957

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of the financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits. These benefits are provided to cover the costs associated with geographic relocation. Mr. Crosswhite relocated from Birmingham, Alabama to Pensacola, Florida in 2011. Mr. Burroughs relocated in 2010 from Atlanta, Georgia to Pensacola, Florida. During 2011, Messrs. Crosswhite and Burroughs received relocation-related benefits in the amount of $338,867 and $37,594, respectively. Relocation assistance includes the incremental cost paid or incurred by Gulf Power for relocation, including loss on home sale and certain capital improvements of residence in former location, home sale and home repurchase assistance (closing costs), shipment of household goods, temporary housing costs during the move, and in some cases a lump sum relocation allowance. Under the relocation policy applicable to all employees, any loss on home sale is determined based on the purchase price paid for the residence plus the cost of capital improvements made within the last five years to the residence that qualify for addition to the tax basis of the residence. Also, as provided in the policy, tax assistance was provided on the taxable relocation benefits, including the reimbursement for loss on home sale. For Mr. Crosswhite, if he terminates within two years of his relocation, the amount provided for loss on home sale, including tax assistance, must be repaid to Gulf Power.

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Personal Use of Corporate-Owned Aircraft. Southern Company owns aircraft that are used to facilitate business travel. If seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included. In connection with Mr. Crosswhite's relocation, the Compensation Committee approved personal use of corporate-owned aircraft for a weekly round-trip between Pensacola and Birmingham for the first six months following his relocation to Pensacola. The incremental cost (primarily fuel costs) of these personal flights was $18,993.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2011

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2011 by the Compensation Committee.

		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Option Awards: Number of Securities Underlying	Exercise or Base Price of Option	Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	Options (#) (i)	Awards ($/Sh) (j)	($) (k)
M. A. Crosswhite	2/14/2011	2,397	239,726	479,452						
	2/14/2011				87	8,663	17,326			311,608
	2/14/2011							63,926	37.97	207,760
R. S. Teel	2/14/2011	1,022	102,222	204,444						
	2/14/2011				23	2,273	4,546			81,760
	2/14/2011							16,774	37.97	54,516
M. L. Burroughs	2/14/2011	728	72,769	145,538						
	2/14/2011				12	1,213	2,426			43,632
	2/14/2011							8,956	37.97	29,107
P. B. Jacob	2/14/2011	1,124	112,448	224,896						
	2/14/2011				25	2,500	5,000			89,925
	2/14/2011							18,452	37.97	59,969
B. C. Terry	2/14/2011	1,132	113,190	226,380						
	2/14/2011				25	2,517	5,034			90,536
	2/14/2011							18,574	37.97	60,366

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2011 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2011 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2011-2013 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

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Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2011, as described in the CD&A, and column (j) the exercise price of the stock options which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2011. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model. The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

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OUTSTANDING EQUITY AWARDS AT 2011 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock award (performance shares) held by or granted to the named executive officers as of December 31, 2011.

	Option Awards				Stock Awards	
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)
M. A. Crosswhite	17,660		32.70	02/18/2015		
	16,497		33.81	02/20/2016		
	22,578		36.42	02/19/2017		
	22,460		35.78	02/18/2018		
	28,161	14,081	31.39	02/16/2019		
	0	25,702	31.17	02/15/2020		
	0	63,926	37.97	02/14/2021		
					130	6,018
R. S. Teel	5,550		32.70	02/18/2015		
	5,771		33.81	02/20/2016		
	9,265		36.42	02/19/2017		
	9,078		35.78	02/18/2018		
	10,221	5,111	31.39	02/16/2019		
	4,710	9,419	31.17	02/15/2020		
	0	16,774	37.97	02/14/2021		
					39	1,805
M. L. Burroughs	316		32.70	02/18/2015		
	289		33.81	02/20/2016		
	1,604		36.42	02/19/2017		
	2,610		35.78	02/18/2018		
	2,572	1,286	31.39	02/16/2019		
	1,207	2,413	31.17	02/15/2020		
	0	8,956	37.97	02/14/2021		
					16	741
P. B. Jacob	13,925		36.42	02/19/2017		
	13,785		35.78	02/18/2018		
	0	9,326	31.39	02/16/2019		
	5,702	17,105	31.17	02/15/2020		
	0	18,452	37.97	02/14/2021		
					53	2,453
B. C. Terry	8,905		33.81	02/20/2016		
	9,367		36.42	02/19/2017		
	12,918		35.78	02/18/2018		
	18,496	9,248	31.39	02/16/2019		
	0	16,963	31.17	02/15/2020		
	0	18,574	37.97	02/14/2021		
					53	2,453

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2005 through 2008 with expiration dates from 2015 through 2018 were fully vested as of December 31, 2011. The options granted in 2009, 2010, and 2011 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested

2009	February 16, 2019	February 16, 2012
2010	February 15, 2020	February 15, 2013
2011	February 14, 2021	February 14, 2014

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Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

Column (f) reflects the threshold number of performance shares that can be earned at the end of each three-year performance period (December 31, 2012 and 2013) that were granted in 2010 and 2011. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2011 ($46.29). See further discussion of performance shares in the CD&A.

OPTION EXERCISES AND STOCK VESTED IN 2011

	Option Awards		Stock Awards	
Name (a)	**Number of Shares Acquired on Exercise (#) (b)**	**Value Realized on Exercise ($) (c)**	**Number of Shares Acquired on Vesting (#) (d)**	**Value Realized on Vesting ($) (e)**
M. A. Crosswhite	12,852	122,217	0	0
R. S. Teel	5,572	58,227	0	0
M. L. Burroughs	0	0	0	0
P. B. Jacob	12,176	112,939	0	0
B. C. Terry	8,482	91,860	0	0

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2011 and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

No stock awards (performance shares) vested in 2011.

PENSION BENEFITS AT 2011 FISCAL YEAR-END

Name (a)	**Plan Name (b)**	**Number of Years Credited Service (#) (c)**	**Present Value of Accumulated Benefit ($) (d)**	**Payments During Last Fiscal Year ($) (e)**
M. A. Crosswhite	Pension Plan	6.92	155,332	0
	SBP-P	6.92	149,088	0
	SERP	6.92	101,967	0
	SRA	15.00	948,334	0
R. S. Teel	Pension Plan	11.33	155,839	0
	SBP-P	11.33	27,532	0
	SERP	11.33	55,679	0
M. L. Burroughs	Pension Plan	19.58	317,062	0
	SBP-P	19.58	14,093	0
	SERP	19.58	113,055	0
P. B. Jacob	Pension Plan	28.42	896,476	0
	SBP-P	28.42	220,768	0
	SERP	28.42	244,200	0
B. C. Terry	Pension Plan	9.50	151,217	0
	SBP-P	9.50	26,754	0
	SERP	9.50	48,912	0
	SRA	10.00	267,297	0

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Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The pay considered for this formula is the base salary rate with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2011 was $245,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation paid during each year is added to the base rates of pay.

Early retirement benefits become payable once plan participants have during employment attained both age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2011, Ms. Terry and Messrs. Crosswhite and Teel were not retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. All the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50. After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of the extra service crediting, the normal plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

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The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When an SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent. Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal* . If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If an SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP also is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included in the section entitled Potential Payments upon Termination or Change in Control.

SRA

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. Information about the supplemental retirement agreements with Ms. Terry and Mr. Crosswhite is included in the CD&A.

The following assumptions were used in the present value calculations:

- Discount rate — 5.00% Pension Plan and 4.65% supplemental plans as of December 31, 2011
- Retirement date — Normal retirement age (65 for all named executive officers)
- Mortality after normal retirement — RP2000 Combined Healthy with generational projections
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement — None
- Form of payment for Pension Benefits
  - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity
  - Female retirees: 40% single life annuity; 40% level income annuity; 10% joint and 50% survivor annuity; and 10% joint and 100% survivor annuity
- Spouse ages — Wives two years younger than their husbands
- Annual performance-based compensation earned but unpaid as of the measurement date — 130% of target opportunity percentages times base rate of pay for year amount is earned
- Installment determination — 4.00% discount rate for single sum calculation and 4.75% prime rate during installment payment period

For all of the named executive officers, the number of years of credited service is one year less than the number of years of employment.

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NONQUALIFIED DEFERRED COMPENSATION AS OF 2011 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
M. A. Crosswhite	23,316	7,698	10,079	0	184,132
R. S. Teel	0	0	28	0	134
M. L. Burroughs	0	0	0	0	0
P. B. Jacob	44,507	214	61,134	0	350,757
B. C. Terry	0	265	2,804	0	73,852

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred — the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.

The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2011, the rate of return in the Stock Equivalent Account was 26.9% which was Southern Company’s total shareholder return for 2011.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States’ largest banks. The interest rate earned on amounts deferred during 2011 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2011. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2011 were the amounts paid for performance under the annual Performance Pay Program and the Performance Dividend Program that were earned as of December 31, 2010 but not payable until the first quarter of 2011. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2011, but not payable until early 2012. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

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Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The chart below shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2011 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2011 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
M. A. Crosswhite	0	0	0
R. S. Teel	0	0	0
M. L. Burroughs	0	0	0
P. B. Jacob	173,710	22,674	196,384
B. C. Terry	121,427	0	121,427

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2011 and assumes that the price of Common Stock is the closing market price on December 31, 2011.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible – Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation – Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off – Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination – Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability – Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I – Acquisition by another entity of 20% or more of Common Stock, or following a merger with another entity Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II – Acquisition by another entity of 35% or more of Common Stock, or following a merger with another entity Gulf Power's shareholders own less than 50% of Gulf Power surviving the merger.

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- Southern Company Termination – A merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control – Acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason – Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

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The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if terminate before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Performance Dividend Program	Paid year of retirement plus two additional years.	Forfeit.	Forfeit.	Payable until options expire or exercised.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration or three years.	Forfeit.
Performance Shares	Prorated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per benefit administration committee’s discretion.	Same as Retirement.
Supplemental Benefit Plan — non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

The chart below describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

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Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP — pension- related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Same as Southern Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Performance Dividend Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at greater of target or actual performance level.	Same as Southern Company Change-in-Control I.	Prorated at greater of actual or target performance level.	If not otherwise eligible for payment, if the program is still in effect, greater of actual or target performance level for year of severance only.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control

events.

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Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2011.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2011 under the Pension Plan, the SBP-P, the SERP and, if applicable, an SRA are itemized in the chart below. The amounts shown under the column Retirement are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2011 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the column Resignation or Involuntary Termination are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2011 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefits amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Ms. Terry and Messrs. Crosswhite and Teel were not retirement-eligible on December 31, 2011. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2011. Therefore she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

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Name		Retirement ($)	Resignation or Involuntary ($)	Death (payments to a spouse) ($)
M. A. Crosswhite	Pension	n/a	634	1,042
	SBP-P	n/a	178,655	19,838
	SERP	n/a	0	13,568
	SRA	n/a	861,310	126,185
R. S. Teel	Pension	n/a	895	1,470
	SBP-P	n/a	35,076	5,093
	SERP	n/a	0	10,300
M. L. Burroughs	Pension	2,146	All plans treated as	1,924
	SBP-P	1,830	retiring	1,830
	SERP	14,685		14,685
P. B. Jacob	Pension	6,556	All plans treated as	4,041
	SBP-P	27,860	retiring	27,860
	SERP	30,817		30,817
B. C. Terry	Pension	n/a	852	1,399
	SBP-P	n/a	34,008	4,968
	SERP	n/a	0	9,083
	SRA	n/a	0	49,636

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P and the SERP could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2011 following a change-in-control event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
M. A. Crosswhite	174,839	119,580	1,112,135	1,406,554
R. S. Teel	34,326	69,418	0	103,745
M. L. Burroughs	18,305	146,848	0	165,153
P. B. Jacob	278,596	308,167	0	586,763
B. C. Terry	33,282	60,846	332,512	426,639

The pension benefit amounts in the tables above were calculated as of December 31, 2011 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.77% discount rate.

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Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2011 is the greater of target or actual performance. Because actual payouts for 2011 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the Summary Compensation Table.

Performance Dividends

Because the assumed termination date is December 31, 2011, there is no additional amount that would be payable other than what was reported in the Summary Compensation Table. As described in the Traditional Termination Events chart, there is some continuation of benefits under the Performance Dividend Program for retirees. However, under Change-in-Control-Related Events, performance dividends are payable at the greater of target performance or actual performance. For the 2008-2011 performance-measurement period, actual performance exceeded target-level performance.

Stock Options and Performance Share Units (Equity Awards)

Equity Awards would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all Equity Awards vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest. There is no payment associated with Equity Awards unless there is a Southern Company Termination and the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. For stock options, that value is the excess of the exercise price and the closing price of Common Stock on December 31, 2011 and for performance shares, it is the closing price on December 31, 2011. The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of
Name	**Stock Options**	**Performance Shares**	**Stock Options**	**Performance Shares**	**Equity Awards ($)**
M. A. Crosswhite	103,709	12,943	211,065	12,943	3,053,797
R. S. Teel	31,304	3,841	75,899	3,841	1,093,739
M. L. Burroughs	12,655	1,614	21,253	1,614	312,608
P. B. Jacob	44,883	5,348	78,295	5,348	1,167,199
B. C. Terry	44,785	5,341	94,471	5,341	1,410,992

DCP and SBP

The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table.

Healthcare Benefits

Messrs. Burroughs and Jacob are retirement-eligible. Healthcare benefits are provided to retirees and there is no incremental payment associated with the termination or change-in-control events. At the end of 2011, the other named executive officers were not retirement-eligible and thus healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing two years of healthcare insurance premiums is $5,538 per year for Ms. Terry and $14,771 per year for Mr. Teel. The estimated cost of providing one year of healthcare insurance premiums is $16,614 per year for Mr. Crosswhite.

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Financial Planning Perquisite

Since Messrs. Burroughs and Jacob are retirement-eligible, an additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement. The other named executive officers are not retirement-eligible.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events.

Severance Benefits

The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for Cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Mr. Crosswhite and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2011 in connection with a change in control.

Name	Severance Amount ($)
M. A. Crosswhite	1,284,538
R. S. Teel	335,383
M. L. Burroughs	260,691
P. B. Jacob	368,332
B. C. Terry	370,723

COMPENSATION RISK ASSESSMENT

Southern Company reviewed its compensation policies and practices, including those of Gulf Power, and concluded that excessive risk-taking is not encouraged. This conclusion was based on an assessment of the mix of pay components and performance goals, the annual pay/performance analysis by the Compensation Committee’s consultant, stock ownership requirements, compensation governance practices, and the “claw-back” provision.

The assessment was reviewed with the Compensation Committee.

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DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2011, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock upon leaving the board;
- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in cash upon leaving the board; or
- at prime interest which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board.

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DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2011, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive Non-Equity Incentive Plan Compensation, and there is no pension plan for non-employee directors.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)	Total ($)
Allan G. Bense	22,000	19,500	0	0	41,500
Deborah H. Calder	22,000	19,500	0	0	41,500
William C. Cramer, Jr.	22,000	19,500	0	0	41,500
J. Mort O'Sullivan III	22,000	19,500	0	0	41,500
William A. Pullum	22,000	19,500	0	0	41,500
Winston E. Scott	22,000	19,500	0	0	41,500

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.
(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.
(3) Above-market earnings on amounts invested in the Director Deferred Compensation Plan. Above-market earnings are defined by the SEC as any amount above 120% of the applicable federal long-term rate as prescribed under Section 1274(d) of the Code.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2011, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or officers serve on the Compensation Committee.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners . Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant:		
	Gulf Power	4,542,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2011. It is based on information furnished by the directors, nominees, and executive officers. The shares owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares outstanding on December 31, 2011.

		Shares Beneficially Owned Include:	
Name of Directors, Nominees, and Executive Officers	**Shares Beneficially Owned (1)**	**Deferred Stock Units (2)**	**Shares Individuals Have Rights to Acquire Within 60 Days (3)**
Mark A. Crosswhite	157,995	0	155,597
Allan G. Bense	946	0	0
Deborah H. Calder	944	504	0
William C. Cramer, Jr.	12,525	12,525	0
J. Mort O'Sullivan III	1,271	1,271	0
William A. Pullum	13,976	13,976	0
Winston E. Scott	5,475	0	0
P. Bernard Jacob	64,907	0	57,441
Michael L. Burroughs	16,321	0	14,076
Richard S. Teel	74,166	0	73,607
Bentina C. Terry	62,975	0	60,007
Directors, Nominees, and Executive Officers as a group (11 people)	411,501	28,276	360,728

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.
(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.
(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change-in-control.

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Equity Compensation Plan Information

The following table provides information as of December 31, 2011 concerning shares of Common Stock authorized for issuance under Southern Company's existing non-qualified equity compensation plans.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights (a)	Weighted-average exercise price of outstanding options, warrants, and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	40,956,822	$33.88	47,802,577 (1)
Equity compensation plans not approved by security holders	n/a	n/a	n/a

(1) Includes shares available for future issuance under the Omnibus Incentive Compensation Plan (46,500,644) and the Outside Directors Stock Plan (1,301,933).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons. None.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/ services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

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Director Independence.

The board of directors of Gulf Power consisted of six non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., J. Mort O'Sullivan, III, William A. Pullum, and Winston E. Scott) and Mr. Crosswhite.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance, including requirements relating to certain board committees. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

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ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2011 and 2010:

	2011	2010
	(in thousands)	
Gulf Power		
Audit Fees (1)	$ 1,326	$ 1,450
Audit-Related Fees (2)	118	0
Tax Fees	0	0
All Other Fees	0	0
Total	$ 1,444	$ 1,450
Southern Power		
Audit Fees (1)	$ 1,270	$ 1,134
Audit-Related Fees	0	0
Tax Fees	0	0
All Other Fees	0	0
Total	$ 1,270	$ 1,134

(1) Includes services performed in connection with financing transactions.
(2) Includes other non-statutory audit services and accounting consultations.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2011 and 2010 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

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THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Chairman, President, and
Chief Executive Officer

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

W. Ron Hinson
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco	*Donald M. James*
Jon A. Boscia	*Dale E. Klein*
Henry A. Clark III	*J. Neal Purcell*
H. William Habermeyer, Jr.	*William G. Smith, Jr.*
Veronica M. Hagen	*Steven R. Specker*
Warren A. Hood, Jr.	*Larry D. Thompson*

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

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ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Charles D. McCrary
President and Chief Executive Officer

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Charles D. McCrary
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
Ralph D. Cook
David J. Cooper, Sr.
Thomas A. Fanning
John D. Johns
Patricia M. King
James K. Lowder
Malcolm Portera
Robert D. Powers
C. Dowd Ritter
James H. Sanford
John Cox Webb, IV

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

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GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: *W. Paul Bowers*
President and Chief Executive Officer

By: */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer,
and Treasurer
(Principal Financial Officer)

Ann P. Daiss
Vice President, Comptroller, and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.	*Charles K. Tarbutton*
Anna R. Cablik	*Beverly Daniel Tatum*
Thomas A. Fanning	*D. Gary Thompson*
Stephen S. Green	*Richard W. Ussery*
Jimmy C. Tallent	*E. Jenner Wood III*

By: */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

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GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: *Mark A. Crosswhite*
President and Chief Executive Officer

By: */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
Vice President and Chief Financial Officer
(Principal Financial Officer)

Constance J. Erickson
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense
Deborah H. Calder
William C. Cramer, Jr.
J. Mort O'Sullivan, III
William A. Pullum
Winston E. Scott

By: */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

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MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Edward Day, VI
President and Chief Executive Officer

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Edward Day, VI
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney
L. Royce Cumbest
Christine L. Pickering
Martha D. Saunders
Philip J. Terrell
M.L. Waters

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

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SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Oscar C. Harper IV
President and Chief Executive Officer

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Michael W. Southern
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie
Thomas A. Fanning
G. Edison Holland, Jr.
Anthony J. Topazi

By: /s/ Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 24, 2012

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INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2011. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2011	$24,919	$66,641	$—	$65,405	$26,155
2010	24,568	62,137	—	61,786	24,919
2009	26,326	58,722	—	60,480	24,568

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2011	$9,602	$16,415	$—	$16,161	$9,856
2010	9,551	18,271	—	18,220	9,602
2009	8,882	21,951	—	21,282	9,551

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

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GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2011	$11,098	$45,267	$—	$43,327	$13,038
2010	9,856	37,004	—	35,762	11,098
2009	10,732	29,088	—	29,964	9,856

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

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GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2011	$2,014	$3,332	$—	$3,384	$1,962
2010	1,913	3,907	—	3,806	2,014
2009	2,188	3,753	—	4,028	1,913

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

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MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2011	$ 638	$1,235	$—	$1,326	$547
2010	940	1,519	—	1,821	638
2009	1,039	2,356	—	2,455	940

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

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EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession

Mississippi Power

(e) 1 - Assignment and Assumption Agreement dated as of October 20, 2011, between Mississippi Power and Juniper Capital L.P. (Designated in Form 8-K dated October 20, 2011, File No. 001-11229, as Exhibit 2.1.)

(e) 2 - Bond Assumption and Exchange Agreement, dated as of October 20, 2011, by and among Mississippi Business Finance Corporation, Mississippi Power, and the bondholders parties thereto. (Designated in Form 8-K dated October 20, 2011, File No. 001-11229, as Exhibit 2.2.)

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 - Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)

(a) 2 - By-laws of Southern Company as amended effective May 26, 2010, and as presently in effect. (Designated in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.2.)

Alabama Power

(b) 1 - Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)

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(b) 2 - By-laws of Alabama Power as amended effective April 22, 2011, and as presently in effect. (Designated in Form 8-K dated April 22, 2011, File No 1-3164, as Exhibit 3.1.)

Georgia Power

(c) 1 - Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)

(c) 2 - By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d) 1 - Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through October 17, 2007. (Designated in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 0-2429, as Exhibit 4.7, and in Form 8-K dated October 16, 2007, File No. 0-2429, as Exhibit 4.5.)

(d) 2 - By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated November 2, 2005, File No. 0-2429, as Exhibit 3.2.)

Mississippi Power

(e) 1 - Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e) 2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3 (e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)

(e) 2 - By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 001-11229, as Exhibit 3(e) 2.)

Southern Power

(f) 1 - Certificate of Incorporation of Southern Power dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)

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(f) 2 - By-laws of Southern Power effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a) 1 - Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through August 23, 2011. (Designated in Form 8-K dated January 11, 2006, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2.)

Alabama Power

(b) 1 - Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2 and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b) 2 - Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through January 18, 2012. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2.)

(b) 3 - Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 4 - Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c) 1 - Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through April 19, 2011. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as

Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2.)

(c) 2 - Senior Note Indenture dated as of March 1, 1998 between Georgia Power, as successor to Savannah Electric, and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through June 30, 2006. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated May 8, 2001, File No. 1-5072, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated November 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated December 10, 2003, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated December 2, 2004, File No. 1-5072, as Exhibit 4.1, and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 4.2.)

Gulf Power

(d) 1 - Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through May 18, 2011. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated May 12, 2011, File No 001-31737, as Exhibit 4.2.)

Mississippi Power

(e) 1 - Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through October 19, 2011. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, and in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b).)

Southern Power

(f) 1 - Senior Note Indenture dated as of June 1, 2002, between Southern Power and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through September 22, 2011. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, and in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4.)

(10) Material Contracts

Southern Company

(a) 1 - Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. (Designated in Southern Company's Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)

(a) 2 - Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)

(a) 3 - Deferred Compensation Plan for Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3.)

(a) 4 - Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)

(a) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(a)2.)

(a) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)

(a) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)

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#	(a)	8	-	Amended Deferred Compensation Agreement, effective December 31, 2008 between Southern Company, SCS, Georgia Power, Gulf Power and G. Edison Holland, Jr. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)2.)
#	(a)	9	-	Separation and Release Agreement between Michael D. Garrett and Georgia Power effective February 22, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)9.)
#	(a)	10	-	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	11	-	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	12	-	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10 (a)18.)
#	(a)	13	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	14	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	15	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
#	(a)	16	-	Form of Restricted Stock Award Agreement. (Designated in Form 10-Q for the quarter ended September 30, 2007, File No. 1-3526, as Exhibit 10(a)1.)
# *	(a)	17	-	Base Salaries of Named Executive Officers.

#	(a)	18	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)5.)
#	(a)	19	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 8-K dated February 9, 2010, File No. 1-3526, as Exhibit 10.1.)
#	(a)	20	-	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3526, as Exhibit 10(a)2.)

Alabama Power

	(b)	1	-	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	-	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(b)	3	-	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	-	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	-	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(b)	6	-	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(b)	7	-	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(b)	8	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(b)	9	-	Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	10	-	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(b)	11	-	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

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#	(b)	12	-	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a) 12 herein.
#	(b)	13	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(b)	14	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(b)	15	-	Base Salaries of Named Executive Officers.
#	(b)	16	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	17	-	Form of Restricted Stock Award Agreement. See Exhibit 10(a)16 herein.
#	(b)	18	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein.
#	(b)	19	-	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)

Georgia Power

	(c)	1	-	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.
	(c)	2	-	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	-	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	-	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	-	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(c)	6	-	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.

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#	(c)	7	-	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	-	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(c)	9	-	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(c)	10	-	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(c)	11	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(c)	12	-	Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)
#	(c)	13	-	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(c)	14	-	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(c)	15	-	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a) 12 herein.
#	(c)	16	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(c)	17	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(c)	18	-	Base Salaries of Named Executive Officers.
#	(c)	19	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)26.)
#	(c)	20	-	Form of Restricted Stock Award Agreement. See Exhibit 10(a)16 herein.
	(c)	21	-	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment

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No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, and Amendment No. 4 thereto dated as of May 2, 2011. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2.)

#	(c)	22	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein.
#	(c)	23	-	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. See Exhibit 10(a)20 herein.
#	(c)	24	-	Separation and Release Agreement between Michael D. Garrett and Georgia Power Company effective February 22, 2011. See Exhibit 10(a)9 herein.
#	(c)	25	-	Retention Agreement between Georgia Power and Michael A. Brown, effective January 1, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-6468, as Exhibit 10(c)1.)

Gulf Power

	(d)	1	-	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.
	(d)	2	-	Unit Power Sales Agreement dated July 19, 1988, between FPC and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(d).)
	(d)	3	-	Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(e).)
	(d)	4	-	Amended Unit Power Sales Agreement dated August 17, 1988, between Jacksonville Electric Authority and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(f).)
#	(d)	5	-	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(d)	6	-	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	7	-	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.

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#	(d)	8	-	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(d)	9	-	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(d)	10	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(d)	11	-	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	12	-	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d)	13	-	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(d)	14	-	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(d)	15	-	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a) 12 herein.
#	(d)	16	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(d)	17	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(d)	18	-	Base Salaries of Named Executive Officers.
#	(d)	19	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10(d)1.)
#	(d)	20	-	Form of Restricted Stock Award Agreement. See Exhibit 10(a)16 herein.
	(d)	21	-	Power Purchase Agreement between Gulf Power and Shell Energy North America (US), L.P. dated March 16, 2009. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2009, File No. 001-31737, as Exhibit 10(d)1.) (Gulf Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Gulf Power omitted such portions from this filing and filed them separately with the SEC.)

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#	(d)	22	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein.
#	(d)	23	-	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	24	-	Deferred Compensation Agreement between Southern Company, Alabama Power, and SCS and Mark A. Crosswhite dated July 30, 2008. (Designated in Alabama Power's Form 10-K for the year ended December 31, 2009, File No. 1-3164, as Exhibit 10(b)21.)

Mississippi Power

	(e)	1	-	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.
	(e)	2	-	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	-	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(e)	4	-	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	-	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	-	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(e)	7	-	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(e)	8	-	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(e)	9	-	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.

#	(e)	10	-	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	11	-	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(e)	12	-	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(e)	13	-	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a) 12 herein.
#	(e)	14	-	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(e)	15	-	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
# *	(e)	16	-	Base Salaries of Named Executive Officers.
#	(e)	17	-	Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)
#	(e)	18	-	Form of Restricted Stock Award Agreement. See Exhibit 10(a)16 herein.
	(e)	19	-	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e) 22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)
#	(e)	20	-	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein.
#	(e)	21	-	Retention Agreement between Edward Day, VI and SCS dated January 22, 2008, Amendment to Retention Agreement dated December 12, 2008, and Amendment of Retention Agreement dated July 29, 2010. (Designated in Mississippi Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-11229, as Exhibit 10(e)2.)

Southern Power

	(f)	1	-	Service contract dated as of January 1, 2001, between SCS and Southern Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)

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(f) 2 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(14) Code of Ethics

Southern Company

(a) - The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 14(a).)

Alabama Power

(b) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

(c) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Gulf Power

(d) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(e) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(f) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) - Subsidiaries of Registrant.

Alabama Power

(b) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

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Georgia Power

(c) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

(d) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

(e) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 - Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 - Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 - Consent of Deloitte & Touche LLP.

Gulf Power

* (d) 1 - Consent of Deloitte & Touche LLP.

Mississippi Power

* (e) 1 - Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 - Consent of Deloitte & Touche LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) - Power of Attorney and resolution.

Alabama Power

* (b) - Power of Attorney and resolution.

Georgia Power

* (c) - Power of Attorney and resolution.

Gulf Power

*	(d)	-	Power of Attorney and resolution.

Mississippi Power

*	(e)		-	Power of Attorney and resolution.

Southern Power

*	(f)		-	Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

*	(a)	1	-	Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(a)	2	-	Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	1	-	Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(b)	2	-	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	1	-	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	-	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	1	-	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	-	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	1	-	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	-	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	1	-	Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	-	Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

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(32) Section 906 Certifications

Southern Company

*	(a)	-	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	-	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	-	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

*	(d)	-	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(e)	-	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(f)	-	Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

*	INS	-	XBRL Instance Document
*	SCH	-	XBRL Taxonomy Extension Schema Document
*	CAL	-	XBRL Taxonomy Calculation Linkbase Document
*	DEF	-	XBRL Definition Linkbase Document
*	LAB	-	XBRL Taxonomy Label Linkbase Document
*	PRE	-	XBRL Taxonomy Presentation Linkbase Document

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

THE SOUTHERN COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of The Southern Company (the "Company") and certain other executive officers of the Company who served during 2011.

Thomas A. Fanning Chairman, President and Chief Executive Officer	$1,125,000
Art P. Beattie Executive Vice President and Chief Financial Officer	$628,732
G. Edison Holland, Jr. Executive Vice President and General Counsel	$639,346
Charles D. McCrary Executive Vice President of the Company, President and Chief Executive Officer of Alabama Power Company	$781,369
W. Paul Bowers Executive Vice President of the Company, President and Chief Executive Officer of Georgia Power Company	$743,585

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

ALABAMA POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Alabama Power Company and certain other executive officers of Alabama Power Company who served during 2011.

Charles D. McCrary President and Chief Executive Officer	$781,369
Philip Raymond Executive Vice President, Chief Financial Officer, and Treasurer	$284,591
Theodore J. McCullough Senior Vice President	$225,884
Steven R. Spencer Executive Vice President	$428,784

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

GEORGIA POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Georgia Power Company and certain other executive officers of Georgia Power Company who served during 2011.

W. Paul Bowers President and Chief Executive Officer	$743,585
Ronnie R. Labrato Executive Vice President, Chief Financial Officer and Treasurer	$302,575
Mickey A. Brown* Executive Vice President	$383,877
Joseph A. Miller Executive Vice President	$403,066

* Salary as of February 1, 2012 retirement date

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

GULF POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Gulf Power Company and certain other executive officers of Gulf Power Company who served during 2011.

Mark A. Crosswhite President and Chief Executive Officer	$411,529
R. Scott Teel Vice President and Chief Financial Officer	$239,083
P. Bernard Jacob Vice President	$254,882
Mike L. Burroughs Vice President	$189,199
Bentina C. Terry Vice President	$256,563

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

MISSISSIPPI POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Mississippi Power Company and certain other executive officers of Mississippi Power Company who served during 2011.

Edward Day, VI President and Chief Executive Officer	$407,056
Moses Feagin Vice President, Treasurer and Chief Financial Officer	$234,073
Thomas O. Anderson Vice President	$194,461
John W. Atherton Vice President	$234,073
Donald R. Horsley* Vice President	$300,706

*Through July 31, 2011

Exhibit 21(a)

Subsidiaries of the Registrant*

Name of Company	Jurisdiction of Organization
The Southern Company	Delaware
Southern Company Holdings, Inc.	Delaware
Alabama Power Company	Alabama
Alabama Power Capital Trust V	Delaware
Alabama Property Company	Alabama
Southern Electric Generating Company	Alabama
Georgia Power Company	Georgia
Piedmont-Forrest Corporation	Georgia
Southern Electric Generating Company	Alabama
Gulf Power Company	Florida
Mississippi Power Company	Mississippi
Southern Power Company**	Delaware

*This information is as of December 31, 2011. In addition, this list omits certain subsidiaries pursuant to paragraph (b)(21)(ii) of Regulation S-K, Item 601.

**Southern Power Company has omitted its list of subsidiaries in accordance with General Instruction I(2)(b) of Form 10-K.

Exhibit 23(a)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-78617, 33-54415, 33-58371, 33-60427, 333-44127, 333-118061, 333-127187, 333-134434, 333-159142, 333-166709, 333-174704, and 333-174707 on Forms S-8 and Registration Statement Nos. 33-3546, 333-09077, 333-64871 (as amended), 333-65178, 333-138503 (as amended), 333-157605, and 333-159072 on Forms S-3 of our report dated February 24, 2012, relating to the consolidated financial statements and consolidated financial statement schedule of The Southern Company, and the effectiveness of The Southern Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2011.

/s/Deloitte & Touche LLP

Atlanta, Georgia
February 24, 2012

Exhibit 23(b)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-172528 on Form S-3 of our report dated February 24, 2012, relating to the financial statements and financial statement schedule of Alabama Power Company, appearing in this Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2011.

/s/Deloitte & Touche LLP

Birmingham, Alabama

February 24, 2012

Exhibit 23(c)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-165133 on Form S-3 of our report dated February 24, 2012, relating to the financial statements and financial statement schedule of Georgia Power Company, appearing in this Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2011.

/s/Deloitte & Touche LLP

Atlanta, Georgia

February 24, 2012

Exhibit 23(d)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-172698 (as amended) on Form S-3 of our report dated February 24, 2012, relating to the financial statements and financial statement schedule of Gulf Power Company, appearing in this Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2011.

/s/Deloitte & Touche LLP

Atlanta, Georgia

February 24, 2012

Exhibit 23(e)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-161168 (as amended) on Form S-3 of our report dated February 24, 2012, relating to the financial statements and financial statement schedule of Mississippi Power Company, appearing in this Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2011.

/s/Deloitte & Touche LLP

Atlanta, Georgia

February 24, 2012

Exhibit 23(f)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-162985 on Form S-3 of our report dated February 24, 2012, relating to the consolidated financial statements of Southern Power Company, appearing in this Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2011.

/s/Deloitte & Touche LLP

Atlanta, Georgia

February 24, 2012

Exhibit 24(a)

February 13, 2012

Melissa K. Caen and Opal N. Shorter

Ladies:

The Southern Company (the “Company”) proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2011 and (2) the Company’s Quarterly Reports on Form 10-Q during 2012.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

THE SOUTHERN COMPANY

By /s/Thomas A. Fanning
Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Juanita Powell Baranco
Juanita Powell Baranco

/s/Jon A. Boscia
Jon A. Boscia

/s/Henry A. Clark III
Henry A. Clark III

/s/Thomas A. Fanning
Thomas A. Fanning

/s/H. William Habermeyer, Jr.
H. William Habermeyer, Jr.

/s/Veronica M. Hagen
Veronica M. Hagen

/s/Warren A. Hood, Jr.
Warren A. Hood, Jr.

/s/Donald M. James
Donald M. James

/s/Dale E. Klein
Dale E. Klein

/s/J. Neal Purcell
J. Neal Purcell

/s/William G. Smith, Jr.
William G. Smith, Jr.

/s/Steven R. Specker
Steven R. Specker

/s/Larry D. Thompson
Larry D. Thompson

/s/G. Edison Holland, Jr.
G. Edison Holland, Jr.

/s/Art P. Beattie
Art P. Beattie

/s/W. Ron Hinson
W. Ron Hinson

Extract from minutes of meeting of the board of directors of The Southern Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and its 2012 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers be and hereby are authorized to give their several powers of attorney to Melissa K. Caen and Opal N. Shorter.

- - - - - - - - - -

The undersigned officer of The Southern Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of The Southern Company, duly held on February 13, 2012, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 24, 2012

THE SOUTHERN COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

SACE 1st Response to Staff 019635

Exhibit 24(b)

Charles D. McCrary
President and
Chief Executive Officer

600 North 18th Street
Post Office Box 2641
Birmingham, Alabama
35291-0001

ALABAMA POWER
A SOUTHERN COMPANY

February 14, 2012

Art P. Beattie
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Melissa K. Caen
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Dear Mr. Beattie and Ms. Caen:

Alabama Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and (2) the Company's Quarterly Reports on Form 10-Q during 2012.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

ALABAMA POWER COMPANY

By / s/Charles D. McCrary
Charles D. McCrary
President and Chief Executive Officer

/s/Whit Armstrong
Whit Armstrong

/s/Ralph D. Cook
Ralph D. Cook

/s/David J. Cooper, Sr.
David J. Cooper, Sr.

/s/Thomas A. Fanning
Thomas A. Fanning

/s/John D. Johns
John D. Johns

/s/Patricia M. King
Patricia M. King

/s/James K. Lowder
James K. Lowder

/s/Charles D. McCrary
Charles D. McCrary

/s/Malcolm Portera
Malcolm Portera

/s/Robert D. Powers
Robert D. Powers

/s/C. Dowd Ritter
C. Dowd Ritter

/s/James H. Sanford
James H. Sanford

/s/John Cox Webb, IV
John Cox Webb, IV

/s/Philip C. Raymond
Philip C. Raymond

/s/Anita Allcorn-Walker
Anita Allcorn-Walker

Extract from minutes of meeting of the board of directors of Alabama Power Company.

\- - - - - - - - - -

> RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2011 and its 2012 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, this Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

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The undersigned officer of Alabama Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Alabama Power Company, duly held on February 14, 2012, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 24, 2012

ALABAMA POWER COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

February 15, 2012

Ronnie R. Labrato, Art P. Beattie and Melissa K. Caen

Gentlemen and Ms. Caen:

Georgia Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and (2) the Company's Quarterly Reports on Form 10-Q during 2012.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,
GEORGIA POWER COMPANY

By /s/W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer

/s/W. Paul Bowers
W. Paul Bowers

/s/Beverly Daniel Tatum
Beverly Daniel Tatum

/s/Robert L. Brown, Jr.
Robert L. Brown, Jr.

/s/D. Gary Thompson
D. Gary Thompson

/s/Anna R. Cablik
Anna R. Cablik

/s/Richard W. Ussery
Richard W. Ussery

/s/Stephen S. Green
Stephen S. Green

/s/E. Jenner Wood III
E. Jenner Wood III

/s/Thomas A. Fanning
Thomas A. Fanning

/s/Ronnie R. Labrato
Ronnie R. Labrato

/s/Jimmy C. Tallent
Jimmy C. Tallent

/s/Ann P. Daiss
Ann P. Daiss

/s/Charles K. Tarbutton
Charles K. Tarbutton

/s/Thomas P. Bishop
Thomas P. Bishop

Extract from minutes of meeting of the board of directors of Georgia Power Company.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2011 and its 2012 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, this Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Ronnie R. Labrato, Art P. Beattie and Melissa K. Caen.

- - - - - - - - -

The undersigned officer of Georgia Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Georgia Power Company, duly held on February 15, 2012, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 24, 2012

GEORGIA POWER COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

October 27, 2011

Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Dear Mr. Beattie and Ms. Caen:

Gulf Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and (2) the Company's Quarterly Reports on Form 10-Q during 2012.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

By /s/Mark A. Crosswhite
Mark A. Crosswhite
President and Chief Executive Officer

/s/Allan G. Bense Allan G. Bense	/s/William A. Pullum William A. Pullum
/s/Deborah H. Calder Deborah H. Calder	/s/Winston E. Scott Winston E. Scott
/s/Mark A. Crosswhite Mark A. Crosswhite	/s/Richard S. Teel Richard S. Teel
/s/William C. Cramer, Jr. William C. Cramer, Jr.	/s/Constance J. Erickson Constance J. Erickson
/s/J. Mort O'Sullivan, III J. Mort O'Sullivan, III	/s/Susan D. Ritenour Susan D. Ritenour

Extract from minutes of meeting of the board of directors of Gulf Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and its 2012 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Gulf Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Gulf Power Company, duly held on October 27, 2011, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 24, 2011

GULF POWER COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

October 26, 2011

Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Mr. Beattie and Ms. Caen:

Mississippi Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and (2) the Company's Quarterly Reports on Form 10-Q during 2012.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

MISSISSIPPI POWER COMPANY

By / s/Edward Day, VI
Edward Day, VI
President, Chief Executive Officer
and Chairman of the Board

/s/Carl J. Chaney Carl J. Chaney	/s/Philip J. Terrell Philip J. Terrell
/s/Edward Day, VI Edward Day, VI	/s/M. L. Waters M. L. Waters
/s/L. Royce Cumbest L. Royce Cumbest	/s/Moses H. Feagin Moses H. Feagin
/s/Christine L. Pickering Christine L. Pickering	/s/Cynthia F. Shaw Cynthia F. Shaw
/s/Martha D. Saunders Martha D. Saunders	/s/Vicki L. Pierce Vicki L. Pierce

Extract from minutes of meeting of the board of directors of Mississippi Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and its 2012 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Mississippi Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Mississippi Power Company, duly held on October 26, 2011, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 24, 2012

MISSISSIPPI POWER COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

November 18, 2011

Ms. Janet J. Hodnett
Southern Power Company
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Ladies:

Southern Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and (2) the Company's Quarterly Reports on Form 10-Q during 2012.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

SOUTHERN POWER COMPANY

By / s/Oscar C. Harper IV
Oscar C. Harper IV
President and Chief
Executive Officer

/s/Art P. Beattie Art P. Beattie	/s/Anthony J. Topazi Anthony J. Topazi
/s/Thomas A. Fanning Thomas A. Fanning	/s/Michael W. Southern Michael W. Southern
/s/Oscar C. Harper IV Oscar C. Harper IV	/s/Janet J. Hodnett Janet J. Hodnett
/s/G. Edison Holland, Jr. G. Edison Holland, Jr.	

Extract from minutes of meeting of the board of directors of Southern Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and its 2012 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Janet J. Hodnett and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Southern Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Southern Power Company, duly held on November 18, 2011, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: February 24, 2012

SOUTHERN POWER COMPANY

By /s/Melissa K. Caen
Melissa K. Caen
Assistant Secretary

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Thomas A. Fanning, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Thomas A. Fanning
Thomas A. Fanning

Chairman, President and Chief Executive Officer

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Art P. Beattie, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Art P. Beattie

Art P. Beattie
Executive Vice President and Chief Financial Officer

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Charles D. McCrary, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Charles D. McCrary
Charles D. McCrary
President and Chief Executive Officer

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Philip C. Raymond, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer and Treasurer

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, W. Paul Bowers, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Ronnie R. Labrato, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Ronnie R. Labrato
Ronnie R. Labrato
Executive Vice President, Chief Financial Officer and Treasurer

GULF POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Mark A. Crosswhite, certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Mark A. Crosswhite
Mark A. Crosswhite
President and Chief Executive Officer

GULF POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Richard S. Teel, certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Richard S. Teel

Richard S. Teel
Vice President and Chief Financial Officer

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Edward Day, VI, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Edward Day, VI
Edward Day, VI

President and Chief Executive Officer

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Moses H. Feagin, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer and Chief Financial Officer

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Oscar C. Harper IV, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Oscar C. Harper IV
Oscar C. Harper IV

President and Chief Executive Officer

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Michael W. Southern, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2012

/s/Michael W. Southern

Michael W. Southern
Senior Vice President, Treasurer and Chief Financial Officer

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2011, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2011, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2011, fairly presents, in all material respects, the financial condition and results of operations of The Southern Company.

/s/Thomas A. Fanning
Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie
Art P. Beattie
Executive Vice President and
Chief Financial Officer

February 24, 2012

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2011, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2011, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2011, fairly presents, in all material respects, the financial condition and results of operations of Alabama Power Company.

/s/Charles D. McCrary
Charles D. McCrary
President and Chief Executive Officer

/s/Philip C. Raymond
Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

February 24, 2012

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2011, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2011, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2011, fairly presents, in all material respects, the financial condition and results of operations of Georgia Power Company.

/s/W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer

/s/Ronnie R. Labrato
Ronnie R. Labrato
Executive Vice President,
Chief Financial Officer and Treasurer

February 24, 2012

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2011, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2011, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2011, fairly presents, in all material respects, the financial condition and results of operations of Gulf Power Company.

/s/Mark A. Crosswhite
Mark A. Crosswhite
President and Chief Executive Officer

/s/Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer

February 24, 2012

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2011, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2011, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2011, fairly presents, in all material respects, the financial condition and results of operations of Mississippi Power Company.

/s/Edward Day, VI
Edward Day, VI
President and Chief Executive Officer

/s/Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer and
Chief Financial Officer

February 24, 2012

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2011, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2011, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2011, fairly presents, in all material respects, the financial condition and results of operations of Southern Power Company.

/s/Oscar C. Harper IV
Oscar C. Harper IV
President and Chief Executive Officer

/s/Michael W. Southern
Michael W. Southern
Senior Vice President, Treasurer and
Chief Financial Officer

February 24, 2012