FILED NOV 06, 2013
DOCUMENT NO. 06778-13
FPSC - COMMISSION CLERK

Comprehensive Exhibit List for Entry into Hearing Record
Docket 130001-EI; November 4-6, 2013

Hearing ID#	Witness	ID# As Filed	Exhibit Description	Entered
STAFF (DIRECT)				
1			Comprehensive Exhibit List	
2	Ileana H. Piedra	IHP-1	Direct testimony of Ileana H. Piedra	
3	Simon O. Ojada	SOO-1	Direct testimony of Simon O. Ojada	
4	Debra Dobiac	DMD-1	Direct testimony of Debra M. Dobiac	
5	Ronald Mavrides	RAM-1	Direct testimony of Ronald A. Mavrides	
FLORIDA POWER & LIGHT (FPL) (DIRECT)				
6	Gerard J. Yupp	GJY-1	August 2012 through December 2012 Hedging Activity True-up Report	
7		GJY-2	FCR 2014 Risk Management Plan	
8		GJY-3	Hedging Activity Report	
9		GJY-4	Fuel Cost Recovery Forecast Assumptions	
10	Terry J. Keith	TJK-1	Fuel Cost Recovery 2012 Final True Up Calculation	
11		TJK-2	Capacity Cost Recovery 2012 Final True Up Calculation	
12		TJK-3	FCR Actual/Estimated True Up Calculation	
13		TJK-4	CCR Actual/Estimated True Up Calculation	
14		TJK-5	Fuel Cost Recovery for January 2014 through May 2014	
15		TJK-6	Fuel Cost Recovery for June 2014 through December 2014 (Including Riviera Beach Energy Center Fuel Savings)	
16		TJK-7	Fuel Cost Recovery for January 2014 through December 2014 (Traditional Methodology)	
17		TJK-8	Capacity Cost Recovery for January 2014 through December 2014	
18		TJK-9	Capacity Cost Recovery 2014 Revenue Requirement Calculation for West County Energy Center Unit 3	
19	Charles R. Rote	JCB-1	Generating Performance Incentive Factor Performance Results for January 2012 through December 2012 (Originally filed by J. Carine Bullock and subsequently adopted by Charles R. Rote)	
20		CRR-1	Generating Performance Incentive Factor Performance Targets for January 2014 through December 2014	
DUKE ENERGY FLORIDA, INC (DEF) (DIRECT)				
21	Thomas Foster	TGF-1T	Fuel Cost Recovery True-Up (January - December 2012)	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 1
PARTY Florida Public Service Commission Staff
DESCRIPTION Comprehensive Exhibit List

Comprehensive Exhibit List for Entry into Hearing Record Docket 130001-EI; November 4-6, 2013				
Hearing ID#	**Witness**	**ID# As Filed**	**Exhibit Description**	**Entered**
22		TGF-2T	Capacity Cost Recovery True-Up (January – Dec. 2012)	
23		TGF-3T	Schedules A1 through A3, A6, and A12 for December 2012	
24		TGF-4T	2012 Capital Structure and Cost Rates	
25		TGF-2	Actual/Estimated True-Up Schedules (January through December 2013)	
26		TGF-3	Projection Factors for January to December 2014	
26A	Joseph McAllister	JM-1T	Hedging Activity Report for the period August – December 2012	
27		JM-1P	2014 Risk Management Plan	
28		JM-2P	Hedging Report, (January-July 2013)	
29	Matthew Jones	MJJ-1T	GPIF Reward/Penalty Schedules for 2012	
30		MJJ-1P	GPIF Targets/Ranges Schedule for January to December 2014	
FLORIDA PUBLIC UTILITIES COMPANY (FPUC) (DIRECT)				
31	Curtis D. Young	CDY-1 revised	Final True Up Schedules (Schedules F-1 and M-1 for FPUC's Divisions)	
32		CDY-2 revised	Estimated/Actual (Schedules El-A, El-B, and El-B1 for the Northwest Division and El-A, El-B, and El-B1 for the Northeast Division)	
33		CDY-3	Schedules El, E1A, E2, E7, and E10 for the Northwest Division and El, E1A, E2, E7, E8, and E10 for the Northeast Division	
34	Cheryl M. Martin	CMM-1	Schedule A (Litigation Costs) and Schedule B (Gulf Power Scenario Savings)	**With-drawn**
35	P. Mark Cutshaw	PMC-1	Schedule C (Schedule of Revenue Requirements for Transmission Plant)	
GULF POWER COMPANY (Gulf) (DIRECT)				
36	H. R. Ball	HRB-1	Coal Suppliers, Natural Gas Price Variance, Hedging Effectiveness	
37		HRB-2	Projected vs. Actual Fuel Cost of System Generation Comparison 2003-2014	
38		HRB-3	Hedging Information Report, August – December 2012	
39		HRB-4	Hedging Information Report, January – July 2013	
40		HRB-5	Risk Management Plan for Fuel Procurement for 2014	
41	Richard W. Dodd	RWD-1	Calculation of Final True-Up and A-Schedules, January 2012 - December 2012	

Comprehensive Exhibit List for Entry into Hearing Record Docket 130001-EI; November 4-6, 2013				
Hearing ID#	**Witness**	**ID# As Filed**	**Exhibit Description**	**Entered**
42		RWD-2	Estimated True-Up, January 2013 - December 2013	
43		RWD-3	Projection, January 2014 - December 2014	
44	M.A. Young	MAY-1	Gulf Power Company GPIF Results, January 2012 - December 2012	
45		MAY-2	Gulf Power Company GPIF Targets and Ranges, January 2014 – December 2014	
TAMPA ELECTRIC COMPANY (TECO) (DIRECT)				
46	Penelope A. Rusk	PAR-1 **Composite**	Final True-up Capacity Cost Recovery (January - December 2012); Final True-up Fuel Cost Recovery (January - December 2012); Actual Fuel True-up compared to Original Estimates (January - December 2013); and Schedules A-1, A-2 and A-6 through A-9 and A-12 (January - December 2012)	
47		PAR-2 **Composite**	Actual/Estimated True-Up Fuel Cost Recovery (January - December 2013); Actual/Estimated True-Up Capacity Cost Recovery (January - December 2013); and Actual/Estimated Polk Unit 1 Ignition Oil Conversion January - December 2013	
48		PAR-3 **Composite**	Projected Capacity Cost Recovery January 2014- December 2014; Projected Capacity Cost Recovery Utilizing Proposed Rate Design January 2014- December 2014; Projected Fuel Cost Recovery January 2014-December 2014; Levelized and Tiered Fuel Rate January 2014- December 2014; and Polk Unit 1 Ignition Oil Conversion January 2014- December 2014	
49	Brian S. Buckley	BSB-1	Generating Performance Incentive Factor True Up for January 2012 – December 2012	
50		BSB-2	Generating Performance Incentive Factor for January 2014 – December 2014	
51	Brent Caldwell	JBC-1	2012 Hedging Activity True-up Report	
52		JBC-2	Fuel Procurement and Wholesale Power Purchase Risk Management Plan 2014	
53		JBC-3	Natural Gas Hedging Activities for January through July 2013	
54			Florida Power & Light Company's response to Staff's First Set of Interrogatories, Nos. 1-12 *[Bates Nos. 0001-0109]*	
55			Florida Power & Light Company's response to Staff's	

Comprehensive Exhibit List for Entry into Hearing Record Docket 130001-EI; November 4-6, 2013				
Hearing ID#	**Witness**	**ID# As Filed**	**Exhibit Description**	**Entered**
			Second Set of Interrogatories, Nos. 13-23 **(Redacted only)** *[Bates Nos. 0110-0129]*	
56			Florida Power & Light Company's response to Staff's Third Set of Interrogatories, Nos. 24-34 *[Bates Nos. 0130-0149]*	
57			Florida Power & Light Company's response to Staff's Fourth Set of Interrogatories, Nos. 35-38 **(Redacted only)** *[Bates Nos. 0150-0158]*	
58			Florida Power & Light Company's response to Staff's Fifth Set of Interrogatories, Nos. 39-42 *[Bates Nos. 0159-0165]*	
59			Florida Power & Light Company's response to Staff's Sixth Set of Interrogatories, Nos. 43-50 *[Bates Nos. 0166-0175]*	
60			Florida Power & Light Company's response to Staff's Seventh Set of Interrogatories, Nos. 51-54 *[Bates Nos. 0176-0181]*	
61			Florida Power & Light Company's response to Staff's Eighth Set of Interrogatories, Nos. 55-57 *[Bates Nos. 0182-0186]*	
62			Florida Power & Light Company's response to Staff's Ninth Set of Interrogatories, Nos. 58-64 *[Bates Nos. 0187-0195]*	
63			Florida Power & Light Company's response to Staff's Tenth Set of Interrogatories, Nos. 65-77, including corrected 76 **(Redacted only)** *[Bates Nos. 0196-0219]*	
64			Florida Power & Light Company's response to OPC's First Set of Interrogatories, Nos. 1-11 *[Bates Nos. 0220-0266]*	
65			Duke Energy Florida's response to Staff's First Set of Interrogatories, Nos. 1-12 *[Bates Nos. 0267-0295]*	
66			Duke Energy Florida's response to Staff's Second Set of Interrogatories, Nos. 13-23 **(Redacted only)** *[Bates Nos. 0296-0307]*	
67			Duke Energy Florida's response to Staff's Third Set of Interrogatories, Nos. 24-34 *[Bates Nos. 0308-0323]*	
68			Duke Energy Florida's response to Staff's Fourth Set of Interrogatories, Nos. 35-38 *[Bates Nos. 0324-0327]*	
69			Duke Energy Florida's response to Staff's Fifth Set of Interrogatories, Nos. 39-40 *[Bates Nos. 0328-0331]*	
70			Duke Energy Florida's response to Staff's Sixth Set of Interrogatories, Nos. 41-48 *[Bates Nos. 0332-0337]*	
71			Duke Energy Florida's response to Staff's Seventh Set of Interrogatories, Nos. 49-62 **(Redacted only)** *[Bates Nos.*	

Comprehensive Exhibit List for Entry into Hearing Record Docket 130001-EI; November 4-6, 2013				
Hearing ID#	**Witness**	**ID# As Filed**	**Exhibit Description**	**Entered**
			0338-0385]	
72			Florida Public Utilities Company's response to Staff's First Set of Interrogatories, Nos. 1-2 *[Bates Nos. 0386-0392]*	
73			Florida Public Utilities Company's response to Staff's Second Set of Interrogatories, No. 3 *[Bates Nos. 0393-0396]*	
74			Florida Public Utilities Company's response to Staff's Third Set of Interrogatories, Nos. 4-8 *[Bates Nos. 0397-0405]*	**With-drawn**
75			Florida Public Utilities Company's response to Staff's Fourth Set of Interrogatories, Nos. 9-21 *[Bates Nos. 0406-0421]*	
76			Gulf Power Company's response to Staff's First Set of Interrogatories, Nos. 1-12 *[Bates Nos. 0422-0460]*	
77			Gulf Power Company's response to Staff's Second Set of Interrogatories, Nos. 13-23 **(Redacted only)** *[Bates Nos. 0461-0478]*	
78			Gulf Power Company's response to Staff's Third Set of Interrogatories, Nos. 24-34 *[Bates Nos. 0479-0497]*	
79			Gulf Power Company's response to Staff's Fourth Set of Interrogatories, No. 35 *[Bates Nos. 0498-0501]*	
80			Gulf Power Company's response to Staff's Fifth Set of Interrogatories, Nos. 37-38 *[Bates Nos. 0502-0506]*	
81			Gulf Power Company's response to Staff's Sixth Set of Interrogatories, Nos. 39-47 *[Bates Nos. 0507-0518]*	
82			Gulf Power Company's response to Staff's Seventh Set of Interrogatories, Nos. 48-59 **(Redacted only)** *[Bates Nos. 0519-0538]*	
83			Tampa Electric Company's responses to Staff's First Set of Interrogatories, Nos. 1-12 *[Bates Nos. 0539-0577]*	
84			Tampa Electric Company's responses to Staff's Second Set of Interrogatories, Nos. 13-23 **(Redacted only)** *[Bates Nos. 0578-0598]*	
85			Tampa Electric Company's responses to Staff's Third Set of Interrogatories, Nos. 24-34 *[Bates Nos. 0599-0618]*	
86			Tampa Electric Company's responses to Staff's Fourth Set of Interrogatories, No 35 *[Bates Nos. 0619-0623]*	
87			Tampa Electric Company's responses to Staff's Fifth Set of Interrogatories, Nos. 36-37 *[Bates Nos. 0624-0629]*	
88			Tampa Electric Company's responses to Staff's Sixth Set of Interrogatories, Nos. 38-45 *[Bates Nos. 0630-0642]*	

Comprehensive Exhibit List for Entry into Hearing Record Docket 130001-EI; November 4-6, 2013				
Hearing ID#	**Witness**	**ID# As Filed**	**Exhibit Description**	**Entered**
89			Tampa Electric Company's responses to Staff's Seventh Set of Interrogatories, Nos. 46-48 *[Bates Nos. 0643-0651]*	
90			Tampa Electric Company's responses to Staff's Eighth Set of Interrogatories, No. 49 *[Bates Nos. 0652-0657]*	
91			Tampa Electric Company's responses to Staff's Ninth Set of Interrogatories, No. 50-61 **(Redacted only)** *[Bates Nos. 0658-0689]*	
92			Staff's proposed revisions to GPIF manual No. 3.516 *[Bates Nos. 690-691]*	
93		**Conf-1**	**[CONFIDENTIAL]** Florida Power & Light Company's response to: Staff's Second Set of Interrogatories, Nos. 13, 16, 17, 20, 21, and 23; Staff's Fourth Set of Interrogatories, No. 37 and Attachment; and Staff's Tenth Set of Interrogatories, Nos. 65 and 66 [FPSC Document Nos. 01490-13, 02268-13, and 06292-13]	
94		**Conf-2**	**[CONFIDENTIAL]** Duke Energy Florida's response to: Staff's Second Set of Interrogatories, Nos. 16-20 and Attachments B & D; and Staff's Seventh Set of Interrogatories, Nos. 49-52, 55, 56 and Attachment [FPSC Document Nos. 01195-13 and 06288-13]	
95		**Conf-3**	**[CONFIDENTIAL]** Gulf Power Company's response to: Staff's Second Set of Interrogatories, Nos. 13, 14, 16, 17, and 20; and Staff's Seventh Set of Interrogatories, Nos. 48, 50, and 54 [FPSC Document Nos. 01171-13 and 06284-13]	
96		**Conf-4**	**[CONFIDENTIAL]** Tampa Electric Company's responses to: Staff's Second Set of Interrogatories, Nos. 13 and 16; and Staff's Ninth Set of Interrogatories, Nos. 50, 55, and 56 [FPSC Document Nos. 01205-13 and 06295-13]	
97	Don Grissette	**FPL**	Corrected response to Staff's Ninth Set of Interrogatories No. 62	
98	Thomas G. Foster	**Duke Energy**	RRSSA Excerpt	
99	Thomas G. Foster	**Duke Energy**	DEF Summary of NEIL Reimbursement	
100	Thomas G. Foster	**Duke Energy**	Composite 2013 & 2014 True-up Schedules (Hearing Exhibits 25 & 26 Excerpts)	
101	Terry J. Keith	**Florida Power & Light**	Revised E-10 Schedules reflecting Storm Charge effective January 1, 2014 per November 1, 2013 Storm Charge routine true-up filling and revised base rate amount effective January	

Comprehensive Exhibit List for Entry into Hearing Record Docket 130001-EI; November 4-6, 2013				
Hearing ID#	**Witness**	**ID# As Filed**	**Exhibit Description**	**Entered**
			1, 2o1 and June 1, 2014 per October 4, 2013 EPU filing	
102	Don Grissette	**Office of Public Counsel**	FPL's Fukushima "Fact Sheets"	

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Miami District Office

Auditor's Report

Florida Power & Light Company
Hedging Activities

Twelve Months Ended July 31, 2013

Docket No. 130001-EI

Audit Control No. 13-102-4-1
September 16, 2013

Iliana H. Piedra
Audit Manager

Yen N. Ngo
Audit Staff

Bety Maitre
Audit Staff

Kathy Welch
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 2
PARTY Florida Public Service Commission Staff
DESCRIPTION Ileana H. Piedra - IHP-1

Table of Contents

Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated April 10, 2013. We have applied these procedures to the schedules prepared by Florida Power & Light Company in support of its 2013 filing for Hedging in Docket No. 130001-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

Definitions

FPL or Utility refers to Florida Power & Light Company.

Accounting Treatment

Objective: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between FPL and its counterparties is consistent with Commission Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and determined that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objective: The objective was to determine whether the gains and losses associated with each financial hedging instrument that FPL implemented are in compliance with Commission Order Numbers PSC-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-PAA-EI, relating to hedging activities.

Procedures: We traced the monthly balances of hedging transactions from FPL's April 5 and August 16, 2013 filings in this docket for the period August 1, 2012, to July 31, 2013 to FPL's Derivative Settlement Report. We selected various hedging transactions from two counterparties from August 2012, June 2013, and July 2013 for natural gas and for heavy oil as a sample and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices, deal tickets, and contracts. We recalculated the gains and losses. For heavy oil we traced the floating price to the confirmation notice, to the calculation of the average pricing from the New York Harbor and agreed the pricing from the average calculation to the Platts publication provided from the Utility. For gas we traced the floating price to the Settlement Price worksheet and to the Gas Daily- Platts Publication provided by the Utility. We compared these recalculated gains and losses with FPL's journal entries for realized gains and losses. We compared a sample of the purchase prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. FPL does not have any tolling agreements where natural gas is provided to generators under purchased power agreements. No exceptions were noted.

Hedged Volume and Limits

Objective: The objective was to determine whether the quantities of natural gas, residual fuel oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2013, and compared them with the Utility's Risk Management Plan. The hedged targets for both natural gas and heavy oil were traced to the Planned Position Strategy Schedule. The fuel burn forecast was traced to the Fuel Burn Summary. The volumes of the oil hedged before and after rebalancing were traced to the Oil Hedged Schedule and the Deal tickets, the percentage hedged was randomly recalculated for accuracy. No exceptions were noted.

Separation of Duties

Objectives: The objectives were to review: FPL's procedures for separating duties related to hedging activities for front office, middle office, and back office and internal and external auditor's work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. We reviewed an internal audit related to the separation of duties. Also, external audit workpapers were reviewed in Docket No. 130001-EI, ACN 13-106-4-1. No exceptions were noted.

Audit Findings

None

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Duke Energy Florida, Inc.
Hedging Activities

Twelve Months Ended July 31, 2013

Docket No. 130001-EI
Audit Control No. 13-102-2-1
September 18, 2013

Simon O. Ojada
Audit Manager

Linda Hill-Slaughter
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI **EXHIBIT** 3
PARTY Florida Public Service Commission Staff
DESCRIPTION Simon 0. Ojada - S00-1

Table of Contents

Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated April 10, 2013. We applied these procedures to the schedules prepared by Duke Energy Florida, Inc. in support of its filing for hedging activities in Docket No. 130001-EI for the twelve months ended July 31, 2013.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

Definition

DEF or Utility refers to Duke Energy Florida, Inc.

Accounting Treatment

Objective: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between DEF and its counterparties is consistent with Commission Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained DEF's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and that the accounting treatment for hedging transactions and transaction costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objective: The objective was to determine whether the gains and losses associated with each financial hedging instrument that DEF implemented are in compliance with Commission Order Numbers: PSC-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-PAA-EI, relating to hedging activities.

Procedures: We traced the monthly balances of hedging transactions from DEF's Hedging Results Report for the period August 1, 2012, to December 30, 2012, and its Hedging Information Report for the period January 1, 2013, to July 31, 2013, to its Hedging Summary by Commodity Reports for 2012 and 2013. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 20 natural gas hedging transactions from August 2012 through July 2013 as a sample and traced them from the Hedging Results and Hedging Information Reports to the third-party confirmation notices and contracts. We recalculated the gains and losses, traced to the price in the confirmation notice, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with the Utility's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objective: The objective was to determine whether the quantities of natural gas, residual fuel oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations for all hedged fuel types. We obtained DEF's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2013, and compared them with the Utility's Risk Management Plan. There were no significant variances noted on natural gas, No. 6 Oil, No 2 Oil, Transportation - Barge, and Transportation - Rail. There were no hedging activities for No. 6 Oil for the last 9 out of the 12 months.

Separation of Duties

Objectives: The objectives were to review DEF's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office, and the Internal and external auditors' work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. We reviewed the Utility Audit Services Department's evaluations for the proper segregation of duties for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. Test results concluded that the internal control procedures in place were "highly effective". In the external auditor's report it was stated that "...in all material respects, effective internal controls over financial reporting as of December 31, 2012,..." are maintained. No exceptions were noted.

Audit Findings

None

,State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tallahassee District Office

Auditor's Report

Gulf Power Company
Hedging Activities

Twelve Months Ended July 31, 2013

Docket No. 130001-EI
Audit Control No. 13-102-1-1
August 30, 2013

Debra M. Dobiac
Audit Manager

Lynn M. Deamer
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 4
PARTY Florida Public Service Commission Staff
DESCRIPTION Debra M. Dobiac - DMD-1

Table of Contents

Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated April 10, 2013. We have applied these procedures to the schedules prepared by Gulf Power Company in support of its filing for hedging activities in Docket No. 130001-EI for the twelve months ended July 31, 2013.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

Definitions

GPC or Utility refers to Gulf Power Company.

Accounting Treatment

Objectives: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between GPC and its counterparties is consistent with Commission Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained GPC's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objectives: The objective was to determine whether the gains and losses associated with each financial hedging instrument that GPC implemented are in compliance with Commission Order Nos. PSC-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-PAA-EI relating to hedging activities.

Procedures: We traced the monthly balances of all hedging transactions from GPC's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2012 to July 31, 2013. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with GPC's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objectives: The objective was to determine whether the quantities of natural gas, residual oil, and purchased power are hedged within the limits (percentage range), as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the

twelve months ended July 31, 2013, and compared them with the Utility's Risk Management Plan. There were immaterial variances for January to July 2013 between the percentages of actual and projected natural gas burned that were hedged. Since the projected burn for August to December 2012 included limited amounts of natural gas burned applicable to the purchased power agreement tolling arrangements, there were significant variances between the percentages of actual and projected natural gas burned that were hedged. These variances were the result of an inaccurate burn forecast.

Segregation of Duties

Objectives: The objectives were to review GPC's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office and internal and external audit work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Audit Findings

None

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Tampa Electric Company
Hedging Activities

Twelve Months Ended July 31, 2013

Docket No. 130001-EI
Audit Control No. 13-102-2-2
September 17, 2013

Ronald A. Mavrides
Audit Manager

Linda Hill-Slaughter
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI **EXHIBIT** 5
PARTY Florida Public Service Commission Staff
DESCRIPTION Ronald A. Mavrides - RAM-1

Table of Contents

Purpose 1

Objectives and Procedures 2

Audit Findings
None 4

Purpose

To: Florida Public Service Commission

We performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Division of Accounting and Finance in its audit service request dated April 9, 2013. We applied these procedures to the schedules prepared by Tampa Electric Company in support of its filing for hedging activities in Docket No. 130001-EI for the twelve months ended July 31, 2013.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

Definition

TECO or Utility refers to the Tampa Electric Company.

Accounting Treatment

Objective: The objective was to determine whether the accounting treatment for futures, options, and swap contracts between TECO and its counterparties is consistent with Commission Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained TECO's supporting detail of the hedging settlements for the twelve months ended July 31, 2013. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objective: The objective was to determine whether the gains and losses associated with each financial hedging instrument that TECO implemented are in compliance with Commission Order Numbers: PSC-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-PAA-EI, relating to hedging activities.

Procedures: We traced the monthly balances of hedging transactions from TECO's Hedging Information Report to its Mark to Market Position Report for the period August 1, 2012, to July 31, 2013. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 31 hedging transactions from the months of February and March 2013 as a sample and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. We recalculated the gains and losses and traced them to the price in the confirmation notice and compared the price to the gas futures rates published by the NYMEX Henry Hub gas futures contract rates. We compared these recalculated gains and losses with the Utility's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

Objective: The objective was to determine whether the quantities of natural gas, residual fuel oil, and purchased power are hedged within the limits (percentage range) as listed in the Utility's Risk Management Plan.

Procedures: We reviewed the quantity limits and authorizations. We obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2013, and compared them with the Utility's Risk Management Plan. There were variances for 4 of the 12 months between the percentages of actual and projected natural gas burned that were hedged. All variances were a result of inaccuate forecasting and unit outages.

Separation of Duties

Objectives: The objectives were to review TECO's procedures for separating duties related to hedging activities for Front Office, Middle Office, and Back Office and the internal and external auditors' workpapers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Audit Findings

None

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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4		FIXED PRICE TRANSACTIONS	[redacted]			
5	YEAR-TO-DATE	SWAPS				
6	(JAN - DEC) 2012	SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
9						$ (671,819,795)
10						
11						
12		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 6
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION G. J. Yupp - GJY-1

GJY-1
Docket No. 130001-EI
FPL Witness: Gerard J. Yupp
Page 1
April 5, 2013

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL HEAVY FUEL OIL PROCUREMENT		
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	YEAR-TO-DATE (JAN - DEC) 2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
9						$ 2,677,666
10						
11						
12		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	January-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	January-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWINGSWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	February-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWINGSWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	February-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	March-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	March-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	April-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	April-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	May-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1				FPL HEAVY FUEL OIL PROCUREMENT		
2				VOLUME (BARRELS)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	May-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	June-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	June-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	July-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	July-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	August-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	August-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	September-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	September-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	October-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	October-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	November-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	November-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	December-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	December-2012	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		SWING SWAPS				
7		OVER-THE-COUNTER OPTIONS				
8		BROKER FEES				
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APPENDIX III

FUEL COST RECOVERY

2014 RISK MANAGEMENT PLAN

GJY-2
DOCKET NO. 130001-EI
FPL WITNESS: G. J. YUPP
August 2, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 7
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION G. J. Yupp - GJY-2

Florida Power and Light Company
2014 Risk Management Plan

Florida Power & Light ("FPL") recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

FPL's risk management plan is based on the following guiding principles:

a) A well-managed hedging program does not involve speculation or market timing. Its primary purpose is not to reduce FPL's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs over time.

b) Hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the hedges were placed. FPL does not predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.

c) Market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, FPL does not intend to "outguess the market" in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.

d) In order to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, it is appropriate to limit hedging to a portion of the total expected volume of fuel purchases.

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel hedging strategy to achieve the goal of fuel price stability (volatility minimization). FPL's fuel hedging strategy aims to reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks when executing its fuel procurement activities. These risks are grouped into four categories as detailed below:

Market Risk

Market Risk is the risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates. Market risk has a direct impact on any open or unhedged energy positions.

Limits ("Limits") are set by the President and Chief Executive Officer ("CEO") of NextEra Energy ("NEE") and delegated to the Exposure Management Committee ("EMC"). The EMC establishes a forum for discussion of NEE's energy risk profile and operations and develops guidelines required for an appropriate risk management control infrastructure, which includes implementation and monitoring of compliance with the NextEra Energy Trading and Risk Management Policy ("Policy"). The EMC has in turn delegated limits to FPL Energy Marketing and Trading ("EMT") for specific portfolios.

Limits (collectively referred to as "Limits") are generally expressed in terms of:

- Maximum portfolio tenor; and
- Open (un-hedged) positions (where appropriate)

The FPL hedging program Limits will be managed in accordance with established corporate guidance. During the ordinary course of business, EMT management will have regard to these NEE Limits, such that pre-approval will be obtained before committing to transactions or contracts which might otherwise cause them to be breached. Adherence to Limits is monitored by the Risk Management Department.

Credit Risk

Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements. Credit Limits are typically established for trading transactions and are designed to manage counterparty credit risk; and set appropriate levels at which to trigger communication concerning risk and strategy.

During the ordinary course of business, EMT management adheres to these credit limits, such that pre-approval is obtained before committing to transactions or contracts which might otherwise cause the credit limits to be breached. Adherence to limits is monitored by the Risk Management Department, as well as dealmakers.

Liquidity Risk

Transacting Liquidity: The availability of market participants willing to transact or having credit quality to transact will have an impact on the utility's ability to execute hedging and risk management strategies.

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances. Risk Management assists the Finance Department by analyzing and monitoring the sufficiency of the allocated portions of the corporate facilities as they relate to EMT liquidity requirements.

Operational Risk

Operating risk is the physical risk associated with maintaining and operating generation assets. The potential risks that FPL encounters with its physical fuel procurement are fuel supply and transportation availability, product quality, delivery timing, weather, environmental, and supplier failure to deliver.

There is also operational risk specific to the wholesale trading activities, relating to inaccurate records of assets and transactions ("Administrative Operational Risk"). Certain personnel are authorized to transact on behalf of FPL and in so doing, can obligate the entity "instantaneously." FPL maintains sufficient controls to ensure that information relating to commitments, obligations and assets are captured accurately, completely and on a timely basis.

Fuel Procurement Oversight/Policies and Procedures (TFB-4, Items 4, 5, 6, 7 and 9)

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing all hedging activities. Changes in strategies and any deviations from the program are approved by the President of FPL or his designee prior to execution. Program activity is included in the Monthly Operations Performance Review ("MOPR") chaired by the CEO of NEE. In addition, the EMC reviews performance and current procurement/hedging activities on a monthly basis.

The utility is supported by an independent middle office Risk Management department that provides oversight of fuel procurement activities. FPL has formal Policy and Procedures documents, signed by all employees, which include controls specifically related to the fuels hedging program. The Risk Management department ensures that the approved execution strategies are followed for each program. Daily and monthly reports are generated and reviewed by the Risk Management department and distributed to various groups, including executive management. Credit reviews are performed by the Risk Management department and included in the reporting mentioned above. Execution strategies must be approved prior to the execution of any transactions and documented as a Planned Position Strategy ("PPS"). All hedge transactions are to be addressed within this strategy document per the ranges and percentages defined in the Risk Management Plan and may be modified from time to time.

Policy and Procedures

As part of this Risk Management Plan, FPL is attaching the latest Policy and Trading and Risk Management Procedures Manual ("Procedures"). NEE updates the Policy and Procedures as necessary. For details that are not covered in this document, please refer to the Policy and Procedures. FPL considers its Policy and Procedures to be confidential.

The NEE corporate risk Policy delineates individual and group transaction limits and authorizations for all fuel procurement activities. The Policy sets out the NEE approach to energy risk and the management of risk, as follows:

- Identification and definition;
- Quantification and measurements;
- Reporting;
- Authority to transact; and
- Ownership and roles and responsibilities.

The Procedures Manual provides guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment.

FPL's deal execution and capture functions coordinate activities across relevant departments, personnel, and systems. This framework of activity properly links the responsibilities of personnel and provides a sufficient medium to resolve issues.

The Procedures clearly list authorized trading personnel, trading limits, tenors, and acceptable instruments. Access to the data entry privileges in the deal capture system is limited to only those individuals who are formally granted permissions to enter trades. All transactions are entered and managed through a centralized deal capture system that supports routine reporting, settlements, and review. Transaction record editing is managed through acceptable authorizations and processes. Credit information is available to traders on a timely basis through daily reporting produced by the Risk Management department. Auditable records of all transactions are maintained and subject to review on a regular basis.

Deal Execution Details

FPL traders receive daily credit reports and credit watch lists from the Risk Management department to ensure that FPL does not enter into a trade with an unauthorized counterparty. FPL traders then select counterparties from this list to transact with as the hedging program is executed. FPL uses a market comparison approach to execute financial hedges. For natural gas, real-time prices can be observed by FPL through electronic tools, such as ICE ("InterContinental Exchange"), FutureSource, or over-the-counter brokers.

FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's hedges.

2014 Hedging Strategy (TFB-4, Items 2 and 8)

FPL plans to hedge a portion of its projected 2015 natural gas requirements during 2014. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions); FPL will implement its hedging program within the following parameters:

Natural Gas

1) FPL will hedge approximately [redacted] of its projected 2015 natural gas requirements within the Hedging Window during 2014. This hedge percentage is consistent with 2014 hedge levels and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements.
2) FPL will utilize [redacted] to hedge its projected natural gas requirements.
3) FPL will execute its natural gas hedges for 2015 from [redacted] through [redacted] as shown below:

Hedging Window

[redacted]

During each month of the Hedging Window, FPL will hedge the percentages shown of its projected 2015 natural gas requirements. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) FPL intends to rebalance its natural gas hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. The monthly tolerance bands for natural gas are [redacted]. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

Heavy Fuel Oil

FPL does not intend to hedge heavy fuel oil for 2015. FPL discontinued fuel oil hedging in 2013 and the factors that influenced that decision still remain.

Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)

FPL reporting systems comprehensively identify, measure, and monitor all forms of risk associated with fuel procurement activities.

FPL's philosophy on reporting is that it should be timely, consistent, flexible, and transparent. Timely and consistent reporting of risk information is critical to the effective management of risk. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, current and historical pricing database, deal information, valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

Specifically, several reports are available at FPL to monitor risk:

Daily Management Report

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details the current energy, spot and forward, unrealized profit and loss, VaR, and position amounts. This report is published only after proper and thorough discussion between Risk Management and desk heads, if necessary for clarification, and resolution of any issues raised.

Credit Exposure Reporting

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details:

- Allowable deal types by counterparty
- Restrictions on counterparties

EMC Update

The Vice President Trading Risk Management provides a formal update to the EMC on a monthly basis. The agenda for the update will be agreed in advance with the EMC Chairman, but at a minimum contains the following items:

- Summary and explanation of significant changes in market risk and fair value;
- Summary and explanation of significant changes in credit risk;
- Exceptions to Risk Management Policy; and

- Minutes of previous EMC update for approval.

Hedge Program Limitations (TFB-4, Item 15)

FPL does not currently have any limitations on implementing certain hedging techniques that would provide a net benefit to customers.

Summary Update on Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) on Utility Hedgers

FPL is monitoring the development of rules related to the Dodd-Frank Act and is actively implementing those rules that affect its business. A number of rules have already been finalized and have become or will become effective over the next few months.

FPL is classified as a bona-fide hedger under the new rules and therefore, FPL will be able to transact swaps in the over-the-counter market without being subject to the mandatory clearing. FPL has signed up for the ISDA protocol 2.0 that became effective on July 1, 2013. This protocol updates agreements between swap dealers and their counterparties with respect to the swap trading relationship documentation and clearing status.

FPL cannot predict the impact that all of these new rules will have on its ability to hedge its commodity risk or on the OTC derivatives market as a whole, but these rules could have a material effect on FPL's risk exposure and financial results. If the still-to-be-finalized margin rules require FPL to post significant amounts of cash collateral with respect to swap transactions, FPL's liquidity could be materially affected and its ability to enter into OTC derivatives to hedge commodity risks could be significantly limited.

Energy Marketing & Trading

A division of Florida Power & Light Company

Trading and Risk Management

Procedures Manual

Revision: June 2013

Approved By the EMC on January 2, 2013
(If the original signature is needed, please contact Risk Management at 304-6028)

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 60]

Trading and Risk Management Procedures Manual

APPROVED BY THE EMC ON:

Last approved on January 3, 2013

(See EMC Emails noting approval. Please contact Risk Management at 304-6028)

NextEra Energy, Inc.
Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 26]

Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 1 through 5]

Planned Position Strategy

EXHIBIT "B"

REDACTED COPIES

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 8
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION G. J. Yupp - GJY-3

	A	B	C	D	E	F
1			FPL NATURAL GAS PROCUREMENT			
2			VOLUME (MMBTU)			
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	YEAR-TO-DATE (JAN - JULY) 2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						$ 25,819,945
9						
10						
11		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

GJY-3
Docket No. 130001-EI
FPL Witness: Gerard J. Yupp
Page 1 of 16
August 16, 2013

CONFIDENTIAL

	A	B	C	D	E	F
1			FPL HEAVY FUEL OIL PROCUREMENT			
2			VOLUME (BARRELS)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	YEAR-TO-DATE	FIXED PRICE TRANSACTIONS	[redacted]			
5	(JAN - JULY)	SWAPS				
6	2013	OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						$ (547,584)
9						
10						
11		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

GJY-3
Docket No. 130001-EI
FPL Witness: Gerard J. Yupp
Page 2 of 16
August 16, 2013

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	January-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

GJY-3
Docket No. 130001-EI
FPL Witness: Gerard J. Yupp
Page 3 of 16
August 16, 2013

CONFIDENTIAL

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4	February-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
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4	February-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
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2			VOLUME (MMBTU)			
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	March-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
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11						

GJY-3
Docket No. 130001-EI
FPL Witness: Gerard J. Yupp
Page 7 of 16
August 16, 2013

CONFIDENTIAL

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2				VOLUME (BARRELS)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	March-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
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2				VOLUME (MMBTU)		
3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	April-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
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4	April-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
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3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	May-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
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9						
10						
11						

GJY-3
Docket No. 130001-EI
FPL Witness: Gerard J. Yupp
Page 11 of 16
August 16, 2013

CONFIDENTIAL

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4	May-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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4	June-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
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4	June-2013	FIXED PRICE TRANSACTIONS	[redacted]			
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3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	July-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
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3	PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	SAVINGS/(COSTS)
4	July-2013	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-4

DOCKET NO. 130001-EI

PAGES 1-4

AUGUST 30, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 9
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION G. J. Yupp - GJY-4

APPENDIX I

FUEL COST RECOVERY

TABLE OF CONTENTS

PAGE	DESCRIPTION	SPONSOR
3	Projected Dispatch Costs	G. J. Yupp
3	Projected Availability of Natural Gas	G. J. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. J. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2014

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.7% Sulfur Grade ($/Bbl)	102.49	102.49	102.49	102.07	102.08	102.08	101.07	101.07	101.07	101.06	101.06	101.06
0.7% Sulfur Grade ($/mmBtu)	16.01	16.01	16.01	15.95	15.95	15.95	15.79	15.79	15.79	15.79	15.79	15.79

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	139.20	138.88	138.16	137.35	136.67	135.99	135.58	135.24	135.06	134.85	134.53	134.21
0.05% Sulfur Grade ($/mmBtu)	23.88	23.82	23.70	23.56	23.44	23.33	23.26	23.20	23.17	23.13	23.08	23.02

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	1,150,000	1,150,000	1,150,000	1,239,000	1,324,000	1,324,000	1,324,000	1,324,000	1,324,000	1,239,000	1,150,000	1,150,000
Firm Gulfstream (mmBtu/Day)	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Non-Firm FGT (mmBtu/Day)	100,000	100,000	100,000	100,000	75,000	30,000	30,000	30,000	30,000	75,000	100,000	100,000
Non-Firm Gulfstream (mmBtu/Day)	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	-	50,000	50,000
Total Projected Daily Availability (mmBtu/Day)	1,995,000	1,995,000	1,995,000	2,084,000	2,144,000	2,099,000	2,049,000	2,049,000	2,049,000	2,009,000	1,995,000	1,995,000
Southeast Supply Header (SESH)**	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000	580,000
Transcontinental Pipe Line (Transco)**	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Gulf South Pipeline Company (Gulf South)**	-	-	-	145,000	145,000	145,000	145,000	145,000	145,000	145,000	-	-

**Note: SESH,Transco and Gulf South firm transportation does not provide increased capacity to FPL's plants but does increase FPL's access to on-shore supply.

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	3.97	3.97	3.94	4.03	4.06	4.09	4.12	4.14	4.15	4.17	4.11	4.29
Firm Gulfstream ($/mmBtu)	3.92	3.92	3.89	3.98	4.00	4.03	4.07	4.08	4.09	4.11	4.06	4.23
Non-Firm FGT ($/mmBtu)	4.58	4.58	4.55	4.64	4.66	4.70	4.73	4.75	4.75	4.78	4.72	4.90
Non-Firm Gulfstream ($/mmBtu)	4.51	4.52	4.49	4.57	4.59	4.63	4.66	4.68	4.68	4.71	4.65	4.82

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	2.29	2.31	2.32	2.31	2.32	2.33	2.36	2.39	2.41	2.41	2.42	2.43
SJRPP ($/mmBtu)	3.27	3.29	3.29	3.31	3.32	3.36	3.40	3.45	3.45	3.46	3.46	3.48

FLORIDA POWER AND LIGHT COMPANY
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral Energy Center	1.3	2.7	2.6	02/22/14 - 02/28/14	03/01/14 - 03/07/14 *			
Ft. Myers 2	0.8	4.0	4.5	11/01/14 - 11/07/14	11/08/14 - 11/14/14 *	11/15/14 - 11/21/14 *		
Ft. Myers 3	0.4	4.0	1.9	05/31/14 - 06/06/14 *	06/08/14 - 06/14/14 *			
Ft. Myers GTs	0.2	3.5	1.0					
Lauderdale 4	1.4	4.0	10.7	02/17/14 - 02/20/14	08/30/14 - 10/03/14			
Lauderdale 5	1.3	4.0	1.1	02/24/14 - 02/27/14				
Lauderdale GTs	0.2	3.5	1.0					
Manatee 1	0.6	4.0	2.7	11/15/14 - 11/24/14				
Manatee 2	1.3	4.0	11.5	02/15/14 - 03/28/14				
Manatee 3	0.9	4.0	9.1	05/23/14 - 06/14/14 *	05/27/14 - 06/18/14 *	05/30/14 - 06/17/14	06/11/14 - 07/03/14 *	07/07/14 - 08/05/14 *
Martin 1	0.5	4.0	38.6	01/01/14 - 05/21/14				
Martin 2	0.1	4.0	77.3	03/25/14 - 12/31/14				
Martin 3	1.1	4.0	1.9	10/18/14 - 10/24/14				
Martin 4	1.1	4.0	15.6	06/30/14 - 08/25/14				
Martin 8	1.0	4.0	1.9	02/15/14 - 02/21/14 *	03/08/14 - 03/21/14 *	03/22/14 - 03/28/14 *		
Port Everglades GTs	0.2	3.5	1.0					
Putnam 1	0.7	4.0	19.0	02/28/14 - 04/03/14	02/28/14 - 05/14/14 *	03/03/14 - 05/15/14 *		
Putnam 2	0.7	4.0	10.4	02/28/14 - 03/29/14	02/28/14 - 04/03/14	10/27/14 - 11/01/14 *		
Riviera 5	2.3	2.7	3.3	12/06/14 - 12/12/14				
Sanford 4	1.0	4.0	5.5	04/24/14 - 04/30/14 *	04/25/14 - 04/30/14	07/12/14 - 08/22/14 *	12/06/14 - 12/12/14 *	12/13/14 - 12/19/14 *
Sanford 5	1.0	4.0	3.3	06/07/14 - 06/13/14	06/07/14 - 06/16/14 *	11/08/14 - 11/17/14 *	11/15/14 - 11/21/14 *	
Scherer 4	1.8	4.0	15.9	02/22/14 - 04/20/14				
St. Johns 1	1.9	4.0	2.2	02/15/14 - 02/22/14				
St. Johns 2	1.7	4.0	15.9	03/01/14 - 04/27/14				
St. Lucie 1	1.2	1.2	0.0	NONE				
St. Lucie 2	1.1	1.1	9.3	03/03/14 - 04/06/14				
Turkey Point 1	0.6	4.0	2.7	12/08/14 - 12/17/14				
Turkey Point 3	1.1	1.1	9.0	03/17/14 - 04/19/14				
Turkey Point 4	1.1	1.1	9.9	09/24/14 - 10/30/14				
Turkey Point 5	0.9	4.0	15.6	02/01/14 - 03/02/14 *	02/15/14 - 02/26/14	02/15/14 - 03/16/14 *	04/25/14 - 06/29/14 *	11/17/14 - 12/07/14
West County 1	1.3	2.7	11.4	09/27/14 - 11/05/14 *	10/01/14 - 11/09/14 *	10/15/14 - 11/09/14	10/15/14 - 11/24/14 *	
West County 2	1.4	2.7	4.7	06/14/14 - 06/29/14 *	06/18/14 - 07/03/14 *	06/23/14 - 06/29/14	06/23/14 - 07/12/14 *	
West County 3	1.5	2.7	6.9	02/15/14 - 03/13/14 *	03/04/14 - 03/30/14 *	03/14/14 - 03/24/14		

* Partial Planned Outage

APPENDIX 1

FUEL COST RECOVERY

2012 FINAL TRUE UP CALCULATION

TJK-1
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-4
EXHIBIT ____
MARCH 1, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 10
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-1

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP

FOR THE PERIOD OF: JANUARY 2012 THROUGH DECEMBER 2012

	Total
1. End of Period True-up [1]	$94,655,667
2. Less: Actual Estimated True-up for the same period [2]	$99,206,321
3. Net True-up for the period	($4,550,654)

[1] From Page 2, Column (14), Lines 32 & 33.

[2] Approved in FPSC Order No. PSC-12-0664-FOF-EI.

( ) Reflects Underrecovery

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD OF: JANUARY 2012 THROUGH DECEMBER 2012

SCHEDULE: E1-B

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Actual	(10) September Actual	(11) October Actual	(12) November Actual	(13) December Actual	(14) Period Total
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3)	$237,588,651	$223,690,078	$248,031,014	$243,673,298	$279,307,523	$305,420,731	$338,696,681	$341,165,884	$301,403,269	$297,650,682	$246,293,270	$255,728,781	$3,318,649,862
3	Nuclear Fuel Disposal Costs (Per A2)	$1,533,571	$1,331,150	$1,025,644	$986,906	$1,231,819	$1,465,162	$1,379,200	$1,218,150	$1,109,649	$1,398,338	$1,323,375	$1,757,630	$15,760,594
4	Scherer Coal Cars Depreciation & Return (Per A2)	($47,585)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($47,585)
5	Fuel Cost of Power Sold (Per A6)	($1,280,730)	($1,239,704)	($385,357)	($330,142)	($334,747)	($907,994)	($665,514)	($377,928)	($467,704)	($802,389)	($1,598,553)	($2,004,093)	($10,394,855)
6	Gains from Off-System Sales (Per A6)	($661,721)	($656,059)	($169,879)	($232,884)	($82,452)	($222,303)	($134,690)	($19,618)	($57,444)	($132,878)	($454,439)	($551,387)	($3,375,754)
7	Fuel Cost of Purchased Power (Per A7)	$6,158,434	$2,629,790	$12,566,896	$23,732,423	$21,448,226	$18,503,612	$27,438,159	$30,451,265	$21,695,916	$14,586,221	$7,826,788	$10,375,796	$197,413,526
8	Energy Payments to Qualifying Facilities (Per A8)	$7,741,501	$3,950,202	$9,383,765	$6,093,903	$9,058,931	$9,876,552	$13,928,525	$16,215,742	$10,620,753	$7,753,543	$2,191,607	$1,886,364	$98,701,388
9	Energy Cost of Economy Purchases (Per A9)	($306,696)	$465,870	$1,978,339	$4,745,050	$4,951,403	$1,480,551	$3,800,890	$9,963,066	$6,357,390	$376,535	($124,288)	$228,635	$33,916,745
10	Total Fuel Costs & Net Power Transactions	$250,725,425	$230,171,327	$272,430,422	$278,688,554	$315,580,703	$335,616,311	$384,443,251	$398,616,561	$340,661,829	$320,830,052	$255,457,760	$267,421,726	$3,650,623,921
11	**Adjustments to Fuel Cost**													
12	Sales to City of Key West (CKW)	($670,275)	($630,502)	($579,079)	($615,288)	($651,163)	($735,092)	($805,703)	($872,772)	($901,434)	($795,134)	($755,239)	($684,198)	($8,695,879)
13	Energy Imbalance Fuel Revenues	$19,819	($2,926)	($24,904)	($39,133)	($37,543)	($71,123)	$1,283,800	$29,698	($42,660)	($15,099)	$55,108	($21,481)	$1,133,556
14	Inventory Adjustments	($53,798)	$11,078	$205,134	$71,452	($191,198)	($331,618)	$103,354	($7,294,497)	($1,445)	($211,913)	$160,370	$16,232	($7,516,849)
15	Non Recoverable Oil/Tank Bottoms - Docket No. 13092	($64,362)	($102,828)	$74,075	$0	($16,447)	$0	$549,227	($115,211)	$1,819,711	$1,187,909	($179,334)	$0	$3,152,740
16	Adjusted Total Fuel Costs & Net Power Transactions	$249,956,809	$229,446,149	$272,105,648	$278,085,585	$314,684,352	$334,478,478	$385,573,929	$390,363,779	$341,536,001	$320,995,815	$254,738,665	$266,732,279	$3,638,697,489
17	**Jurisdictional kWh Sales**													
18	Jurisdictional kWh Sales	7,840,404,689	6,965,004,441	7,465,369,459	8,057,607,586	8,207,468,174	9,555,068,717	9,956,736,569	10,258,713,687	9,847,231,749	9,298,734,059	7,574,513,864	7,198,695,149	102,225,548,143
19	Sale for Resale (excluding CKW) [1]	141,688,445	145,961,604	143,638,859	162,448,949	157,386,681	185,257,965	184,819,920	201,148,742	203,666,851	181,902,894	171,047,037	132,357,331	2,011,325,278
20	Sub-Total Sales (excluding CKW)	7,982,093,134	7,110,966,045	7,609,008,318	8,220,056,535	8,364,854,855	9,740,326,682	10,141,556,489	10,459,862,429	10,050,898,600	9,480,636,953	7,745,560,901	7,331,052,480	104,236,873,421
21														
22	**Jurisdictional % of Total Sales (Line 18/20)**	98.22492%	97.94737%	98.11225%	98.02375%	98.11848%	98.09803%	98.17760%	98.07695%	97.97365%	98.08132%	97.79168%	98.19457%	N/A
23	**True-up Calculation**													
24	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$284,993,002	$250,837,229	$269,729,572	$290,359,370	$297,287,803	$349,928,235	$366,419,368	$378,952,669	$362,032,432	$339,901,215	$274,530,139	$259,684,699	$3,724,655,733
25	**Fuel Adjustment Revenues Not Applicable to Period**													
26	Prior Period True-up (Collected)/Refunded This Period [2]	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($4,316,701)	($51,800,406)
27	GPIF, Net of Revenue Taxes [3]	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($547,226)	($6,566,718)
28	Jurisdictional Fuel Revenues Applicable to Period	$280,129,075	$245,973,302	$264,865,645	$285,495,443	$292,423,876	$345,064,308	$361,555,441	$374,088,743	$357,168,505	$335,037,288	$269,666,212	$254,820,772	$3,666,288,610
29	Adjusted Total Fuel Costs & Net Power Transactions	$249,956,809	$229,446,149	$272,105,648	$278,085,585	$314,684,352	$334,478,478	$385,573,929	$390,363,779	$341,536,001	$320,995,815	$254,738,665	$266,732,279	$3,638,697,489
30	Jurisdictional Sales % of Total kWh Sales (Line 22)	98.22492%	97.94737%	98.11225%	98.02375%	98.11848%	98.09803%	98.17760%	98.07695%	97.97365%	98.08132%	97.79168%	98.19457%	98.07043%
31	Jurisdictional Total Fuel Costs & Net Power Transactions (Line 29x30x1.00085)	$245,728,568	$224,927,495	$267,195,897	$272,821,620	$309,025,952	$328,395,697	$378,868,995	$383,182,317	$334,899,709	$315,104,544	$249,324,966	$262,139,244	$3,571,615,003
32	True-up Provision for the Month - Over/(Under) Recovery (Line 28 - Line 31)	$34,400,508	$21,045,807	($2,330,252)	$12,673,823	($16,602,076)	$16,668,611	($17,313,554)	($9,093,574)	$22,268,796	$19,932,744	$20,341,246	($7,318,472)	$94,673,607
33	Interest Provision for the Month	($5,223)	($4,936)	($3,154)	($2,483)	($2,712)	($2,077)	($1,843)	($3,210)	($1,371)	$853	$4,275	$3,940	($17,940)
34	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($51,800,406)	($13,088,421)	$12,269,151	$14,252,445	$31,240,486	$18,952,399	$39,935,634	$26,936,938	$22,156,854	$48,740,980	$72,991,277	$97,653,498	($51,800,406)
35	Deferred Final True-up - Over/(Under) Recovery [4]	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)	($51,121,025)
36	Prior Period True-up Collected/(Refunded) This Period [2]	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$4,316,701	$51,800,406
37	End of Period Net True-up Amount Over/(Under) Recovery (Lines 32 through 36)	($64,209,445)	($38,851,875)	($36,868,579)	($19,880,539)	($32,168,626)	($11,185,391)	($24,184,087)	($28,964,170)	($2,380,046)	$21,870,252	$46,532,473	$43,534,642	$43,534,642
38														

(1) Billed KWH includes all wholesale customers except CKW.

(2) Prior Period 2010/2011 True-up.

(3) Generation Performance Incentive Factor is (($6,571,449/12) x 99.9280%) - See Order No. PSC-11-0579-FOF-EI.

(4) Deferred 2011 Final True-up.

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

FOR THE PERIOD OF: JANUARY 2012 THROUGH DECEMBER 2012

	(1)	(2)	(3)	(4)
Line No.	Revenue/Cost Final Variance Analysis	FINAL TRUE-UP	ACTUAL/ESTIMATED	Difference
1	**Jurisdictional Fuel Revenues**			
2	Revenues	$3,724,655,733	$3,731,467,296	($6,811,562)
3	MWH	102,225,548	102,165,119	60,429
4	$ per MWH	36.43566	36.52389	(0.08822)
5				
6	Variance due to Consumption			$2,207,101
7	Variance due to Cost			($9,018,664)
8	Total Variance			($6,811,562)
9				
10	**Jurisdictional Total Fuel Costs**			
11	Costs	$3,571,615,003	$3,573,860,404	($2,245,401)
12	MWH	102,225,548	102,165,119	60,429
13	$ per MWH	34.93858	34.98122	(0.04264)
14				
15	Variance due to Consumption			$2,113,880
16	Variance due to Cost			($4,359,280)
17	Total Variance			($2,245,401)
18				
19	**Total Variance**			
20	Variance due to Consumption			$93,222
21	Variance due to Cost			($4,659,384)
22	Total Variance			($4,566,163)
23	Interest			$15,509
24	Total True-up			($4,550,654)
25				
26				
27	( ) Reflect Underrecovery			
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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL vs. ACTUAL/ESTIMATED

FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

Line No.	(1)	(2) FCR - 2012 Final True-up	(3) FCR - 2012 Actual Estimated - Actuals Through July	(4) Dif. FCR - 2012 Actual Estimated - Actuals Through July	(5) % Dif. FCR - 2012 Actual Estimated - Actuals Through July
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3)	$3,318,649,862	$3,281,527,049	$37,122,813	1.1%
3	Nuclear Fuel Disposal Costs (Per A2)	$15,760,594	$16,594,958	($834,364)	(5.0%)
4	Scherer Coal Cars Depreciation & Return (Per A2)	($47,585)	($47,585)	($0)	0.0%
5	Fuel Cost of Power Sold (Per A6)	($10,394,855)	($14,648,284)	$4,253,429	(29.0%)
6	Gains from Off-System Sales (Per A6)	($3,375,754)	($3,950,890)	$575,136	(14.6%)
7	Fuel Cost of Purchased Power (Per A7)	$197,413,526	$204,717,856	($7,304,330)	(3.6%)
8	Energy Payments to Qualifying Facilities (Per A8)	$98,701,388	$133,527,387	($34,825,999)	(26.1%)
9	Energy Cost of Economy Purchases (Per A9)	$33,916,745	$32,546,458	$1,370,287	4.2%
10	Total Fuel Costs & Net Power Transactions	$3,650,623,921	$3,650,266,950	$356,971	0.0%
11	**Adjustments to Fuel Cost**				
12	Sales to City of Key West (CKW)	($8,695,879)	($8,918,099)	$222,220	(2.5%)
13	Energy Imbalance Fuel Revenues	$1,133,556	$1,127,991	$5,565	0.5%
14	Inventory Adjustments	($7,516,849)	($185,596)	($7,331,253)	3,950.1%
15	Non Recoverable Oil/Tank Bottoms - Docket No. 13092	$3,152,740	$439,665	$2,713,075	617.1%
16	Adjusted Total Fuel Costs & Net Power Transactions	$3,638,697,489	$3,642,730,911	($4,033,422)	(0.1%)
17	**Jurisdictional kWh Sales**				
18	Jurisdictional kWh Sales	102,225,548,143	102,165,119,159	60,428,984	0.1%
19	Sale for Resale (excluding CKW)	2,011,325,278	2,058,288,295	(46,963,017)	(2.3%)
20	Sub-Total Sales (excluding CKW)	104,236,873,421	104,223,407,454	13,465,967	0.0%
21					
22	**Jurisdictional % of Total Sales (Line 18/20)**	N/A	N/A	N/A	N/A
23	**True-up Calculation**				
24	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,724,655,733	$3,731,467,296	($6,811,562)	(0.2%)
25	**Fuel Adjustment Revenues Not Applicable to Period**				
26	Prior Period True-up (Collected)/Refunded This Period [1]	($51,800,406)	($51,800,406)	$0	0.0%
27	GPIF, Net of Revenue Taxes [2]	($6,566,718)	($6,566,718)	$0	0.0%
28	Jurisdictional Fuel Revenues Applicable to Period	$3,666,288,610	$3,673,100,172	($6,811,562)	(0.2%)
29	Adjusted Total Fuel Costs & Net Power Transactions	$3,638,697,489	$3,642,730,911	($4,033,422)	(0.1%)
30	Jurisdictional Sales % of Total kWh Sales (Line 22)	N/A	N/A	N/A	N/A
31	Jurisdictional Total Fuel Costs & Net Power Transactions (Line 29x30x1.00085)	$3,571,615,003	$3,573,860,404	($2,245,401)	(0.1%)
32	True-up Provision for the Month - Over/(Under) Recovery (Line 28 - Line 31)	$94,673,607	$99,239,770	($4,566,163)	(4.6%)
33	Interest Provision for the Month	($17,940)	($33,449)	$15,509	(46.4%)
34	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($51,800,406)	($51,800,406)	$0	0.0%
35	Deferred Final True-up - Over/(Under) Recovery	($51,121,025)	($51,121,025)	$0	0.0%
36	Prior Period True-up Collected/(Refunded) This Period [1]	$51,800,406	$51,800,406	$0	0.0%
37	End of Period Net True-up Amount Over/(Under) Recovery (Lines 32 through 36)	$43,534,642	$48,085,296	($4,550,654)	(9.5%)
38					
39	[1] Prior Period 2010/2011 Net True-up				
40	[2] Generation Performance Incentive Factor is (($6,571,449/12) x 99.9280%) - See Order No. PSC-11-0579-FOF-EI.				
41					
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43					

APPENDIX II

CAPACITY COST RECOVERY

2012 FINAL TRUE UP CALCULATION

TJK-2
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-5
EXHIBIT ____
MARCH 1, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 11
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-2

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

Line No.		2012
1	End of Period True-up for the period January through December 2012 [1]	($23,791,944)
2	Less - Estimated/Actual True-up for the same period [2]	($15,878,460)
3	Net True-up for the period January through December 2012	($7,913,484)
4		
5	[1] From Page 2, Column (14), Lines 16 & 17.	
6	[2] Approved in FPSC Order No. PSC-12-0664-FOF dated December 21, 2012.	
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8	( ) Reflects Underrecovery	
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Actual	(10) September Actual	(11) October Actual	(12) November Actual	(13) December Actual	(14) Total
1	Payments to Non-cogenerators	$16,212,289	$18,735,487	$17,260,731	$19,897,479	$17,649,852	$18,338,941	$18,371,831	$18,499,389	$18,163,391	$16,789,946	$17,450,102	$16,961,656	$214,331,095
2	Payments to Co-generators	$25,047,746	$24,589,854	$24,964,259	$25,107,774	$24,536,250	$25,841,540	$25,154,871	$25,144,912	$25,095,059	$25,403,546	$25,368,502	$25,192,701	$301,447,014
3	SJRPP Suspension Accrual	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$77,987	$935,844
4	Return on SJRPP Suspension Liability	($444,180)	($444,804)	($445,428)	($446,053)	($446,677)	($447,301)	($447,925)	($448,549)	($449,173)	($449,797)	($450,421)	($451,045)	($5,371,351)
5	Incremental Plant Security Costs-Order No. PSC-02-1761	$3,155,284	$2,826,276	$2,979,759	$3,069,584	$3,232,072	$3,030,391	$3,018,723	$2,726,382	$3,531,375	$2,853,223	$3,049,160	$4,372,180	$37,844,409
6	Transmission of Electricity by Others	$2,202,085	$2,539,767	$2,793,846	$213,714	$1,382,621	($694,480)	$804,439	$497,852	$1,246,011	$1,690,885	$2,199,119	$2,320,901	$17,196,760
7	Transmission Revenues from Capacity Sales	($183,416)	($189,248)	$25,792	($65,281)	($24,007)	($83,793)	($43,542)	($5,041)	($14,295)	($63,992)	($148,968)	($191,835)	($987,627)
8	Total (Lines 1 through 7)	$46,067,795	$48,135,319	$47,656,946	$47,855,204	$46,408,099	$46,063,285	$46,936,384	$46,492,932	$47,650,355	$46,301,798	$47,545,480	$48,282,545	$565,396,143
9	Jurisdictional Separation Factor [a]	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	N/A
10	Jurisdictional Capacity Charges	$45,152,866	$47,179,328	$46,710,455	$46,904,776	$45,486,411	$45,148,446	$46,004,204	$45,569,559	$46,703,995	$45,382,221	$46,601,203	$47,323,629	$554,167,093
11	Nuclear Cost Recovery Costs	$12,722,828	$12,890,348	$16,437,588	$15,015,050	$15,273,871	$19,744,593	$16,537,502	$16,638,363	$17,111,442	$17,427,238	$17,634,384	$18,655,606	$196,088,812
12	Jurisdictional Capacity Charges Authorized for Recovery through the CCR clause	$57,875,694	$60,069,676	$63,148,043	$61,919,826	$60,760,282	$64,893,039	$62,541,706	$62,207,922	$63,815,436	$62,809,459	$64,235,587	$65,979,235	$750,255,904
13	CCR Revenues (Net of Revenue Taxes)	$53,321,438	$48,321,333	$51,351,805	$54,944,454	$56,137,491	$64,510,352	$67,627,868	$69,862,447	$67,142,792	$63,377,288	$52,079,034	$49,230,795	$697,907,097
14	Prior Period True-up Provision	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$2,384,023	$28,608,272
15	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$55,705,461	$50,705,356	$53,735,828	$57,328,477	$58,521,514	$66,894,375	$70,011,891	$72,246,469	$69,526,814	$65,761,311	$54,463,056	$51,614,818	$726,515,369
16	True-up Provision for Month - Over/(Under) Recovery (Line 15 - Line 12)	($2,170,233)	($9,364,320)	($9,412,215)	($4,591,349)	($2,238,768)	$2,001,336	$7,470,185	$10,038,547	$5,711,378	$2,951,852	($9,772,530)	($14,364,417)	($23,740,535)
17	Interest Provision for Month	($1,148)	($2,541)	($3,190)	($4,173)	($5,574)	($5,365)	($5,591)	($5,713)	($3,658)	($3,488)	($5,707)	($5,260)	($51,409)
18	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$28,608,272	$24,052,868	$12,301,984	$502,556	($6,476,989)	($11,105,353)	($11,493,405)	($6,412,834)	$1,235,978	$4,559,675	$5,124,017	($7,038,244)	$28,608,272
19	Deferred True-up - Over/(Under) Recovery	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)	($44,704,575)
20	Prior Period True-up Provision - Collected/(Refunded) this Month	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($2,384,023)	($28,608,272)
21	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	($20,651,707)	($32,402,591)	($44,202,019)	($51,181,564)	($55,809,928)	($56,197,980)	($51,117,409)	($43,468,597)	($40,144,900)	($39,580,558)	($51,742,819)	($68,496,519)	($68,496,519)
22														
23	[a] As approved in Order No PSC-11-0579-FOF-EI.													
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

Line No.	(1) CCR - Final True-up Variance	(2) CCR - 2012 Final True-up	(3) CCR - 2012 Actual Estimated	(4) Dif. CCR - 2012 Actual Estimated	(5) % Dif. CCR - 2012 Actual Estimated
1	Payments to Non-cogenerators	$214,331,095	$214,470,011	($138,916)	(0.1%)
2	Payments to Co-generators	$301,447,014	$297,794,075	$3,652,939	1.2%
3	SJRPP Suspension Accrual	$935,844	$935,844	$0	0.0%
4	Return on SJRPP Suspension Liability	($5,371,351)	($5,371,351)	$0	0.0%
5	Incremental Plant Security Costs-Order No. PSC-02-1761	$37,844,409	$39,862,475	($2,018,066)	(5.1%)
6	Transmission of Electricity by Others	$17,196,760	$16,824,422	$372,338	2.2%
7	Transmission Revenues from Capacity Sales	($987,627)	($1,051,995)	$64,367	(6.1%)
8	Total (Lines 1 through 7)	$565,396,143	$563,463,481	$1,932,662	0.3%
9	Jurisdictional Separation Factor [a]	98.01395%	98.01395%	0.00000%	(0.0%)
10	Jurisdictional Capacity Charges	$554,167,093	$552,272,814	$1,894,279	0.3%
11	Nuclear Cost Recovery Costs	$196,088,812	$196,089,735	($923)	(0.0%)
12	Jurisdictional Capacity Charges Authorized for Recovery through the CCR clause	$750,255,904	$748,362,549	$1,893,356	0.3%
13	CCR Revenues (Net of Revenue Taxes)	$697,907,097	$703,932,889	($6,025,791)	(0.9%)
14	Prior Period True-up Provision	$28,608,272	$28,608,272	$0	N/A
15	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$726,515,369	$732,541,161	($6,025,791)	(0.8%)
16	True-up Provision for Month - Over/(Under) Recovery (Line 15 - Line 12)	($23,740,535)	($15,821,388)	($7,919,147)	50.1%
17	Interest Provision for Month	($51,409)	($57,071)	$5,663	(9.9%)
18	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$28,608,272	$28,608,272	$0	N/A
19	Deferred True-up - Over/(Under) Recovery	($44,704,575)	($44,704,575)	$0	N/A
20	Prior Period True-up Provision - Collected/(Refunded) this Month	($28,608,272)	($28,608,272)	$0	N/A
21	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	($68,496,519)	($60,583,035)	($7,913,484)	13.1%
22					
23	[a] As Approved in Order No. PSC-11-0579-FOF-EI.				
24					
25	Columns and Rows may not add due to rounding.				
26					
27					
28					
29					
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35					
36					
37					

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 1 of 2

For the Month of **Dec-12**

Contract	Capacity MW	Term Start	Term End	Contract Type	
Cedar Bay	250	1/25/1994	12/31/2024	QF	
Indiantown	330	12/22/1995	12/1/2025	QF	
Broward North - 1991 Agreement	11	1/1/1993	12/31/2026	QF	
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF	
SWAPC	40	1/1/2012	12/31/2032	QF	SUBJECT TO ANNUAL NOTIFICATION - MW

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	12,182,233	11,771,326	12,009,522	12,219,024	11,647,500	12,966,537	12,279,868	12,228,668	12,178,815	12,256,130	12,417,890	12,259,274	146,416,787
ICL	11,453,088	11,406,103	11,542,312	11,476,325	11,476,325	11,462,578	11,462,578	11,503,818	11,503,818	11,734,991	11,538,187	11,521,003	138,081,127
BN-NEG '91	310,750	310,750	310,750	310,750	310,750	310,750	310,750	310,750	310,750	310,750	310,750	310,750	3,729,000
BS-NEG '91	98,875	98,875	98,875	98,875	98,875	98,875	98,875	98,875	98,875	98,875	98,875	98,875	1,186,500
SWAPC	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	1,002,800	12,033,600
Total	25,047,746	24,589,854	24,964,259	25,107,774	24,536,250	25,841,540	25,154,871	25,144,912	25,095,059	25,403,546	25,368,502	25,192,701	301,447,014

Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 2 of 2

For the Month of **Dec-12**

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Oleander Power Project L.P.	Other Entity	June 1, 2002	September 30, 2012
2	Southern Co. - UPS Scherer	Other Entity	June, 2010	December 31, 2015
3	Southern Co. - UPS Harris	Other Entity	June, 2010	December 31, 2015
4	Southern Co. - UPS Franklin	Other Entity	June, 2010	December 31, 2015
5	JEA - SJRPP	Other Entity	April, 1982	September 30, 2021
6	DeSoto	Other Entity	January 1, 2012	December 31, 2012
7	Tampa Electric Company	Other Entity	January 1, 2012	December 31, 2012
8	Seminole Electric Cooperative, Inc.	Other Entity	April 1, 2012	September 30, 2012
9	Other Short Term PPA's	Other Entity	Various	Various

2012 Capacity in MW

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	155	155	155	155	155	155	155	155	155	-	-	-
2	163	163	163	163	163	163	163	163	163	163	163	163
3	600	600	600	600	600	600	600	600	600	600	600	600
4	190	190	190	190	190	190	190	190	190	190	190	190
5	375	375	375	375	375	375	375	375	375	375	375	375
6	305	305	305	305	305	305	305	305	305	305	305	305
7	75	25	25	125	125	125	125	125	125	125	75	75
8				150	150	150	150	150	150	-		
9												
Total	1,863	1,813	1,813	2,063	2,063	2,063	2,063	2,063	2,063	1,758	1,708	1,708

2012 Capacity in Dollars

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total	16,212,289	18,528,445	18,373,623	18,718,337	17,649,852	18,338,941	18,371,831	18,772,681	18,163,391	16,789,946	17,450,102	16,961,656

Year-to-date Short Term Capacity Payments	214,331,095

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1												
2												
3												
4												
5												
6												
7												
8												

True ups												
1												
2												
3												
4												
5												
6												
7												
8												
9												

APPENDIX I

FUEL COST RECOVERY

ACTUAL/ESTIMATED TRUE UP CALCULATION

TJK-3
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
August 2, 2013

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	130001-EI	**EXHIBIT**	12
PARTY	Florida Power & Light Co. (FPL) (Direct)		
DESCRIPTION	Terry J. Keith - TJK-3		

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE

SCHEDULE: E1-B

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) [1]	$220,037,900	$208,050,632	$234,633,600	$267,219,326	$276,720,275	$286,666,776	$299,597,033	$301,405,743	$286,677,773	$267,474,908	$214,522,470	$219,862,398	$3,082,868,833
3	Nuclear Fuel Disposal Costs (Per A2)	$1,880,395	$1,417,734	$1,144,529	$1,819,397	$2,007,177	$2,256,251	$2,341,856	$2,341,856	$2,244,819	$1,675,564	$2,260,197	$2,403,658	$23,793,433
4	Scherer Coal Cars Depreciation & Return	$0	($181)	($46,136)	($207)	($416)	($416)	($53,088)	$0	$0	$0	$0	$0	($100,444)
5	Fuel Cost of Power Sold (Per A6)	($3,701,519)	($6,549,357)	($8,851,076)	($6,190,755)	($4,716,820)	($3,101,107)	($4,247,107)	($4,826,707)	($2,968,118)	($1,792,000)	($3,741,229)	($5,638,407)	($56,324,203)
6	Gains from Off-System Sales (Per A6)	($876,040)	($1,741,631)	($2,183,089)	($1,053,380)	($1,015,087)	($688,662)	($516,250)	($588,750)	($278,750)	($312,500)	($675,000)	($1,277,500)	($11,206,639)
7	Fuel Cost of Purchased Power (Per A7)	$7,594,732	$6,358,940	$3,174,645	$14,997,896	$15,862,340	$24,618,502	$17,098,920	$16,190,014	$17,178,160	$14,461,104	$9,027,553	$8,443,059	$155,005,864
8	Energy Payments to Qualifying Facilities (Per A8)	$1,679,537	$1,308,964	$6,001,429	$9,692,457	$10,992,302	$11,182,480	$14,320,667	$14,505,666	$15,353,663	$10,077,669	$5,485,671	$3,385,672	$103,986,176
9	Energy Cost of Economy Purchases (Per A9)	$98,806	$63,673	$148,556	$1,639,283	$121,100	$186,471	$250,000	$500,000	$1,350,000	$1,225,000	$56,000	$44,000	$5,682,889
10	Total Fuel Costs & Net Power Transactions	$226,713,811	$208,908,774	$234,022,458	$288,124,017	$299,970,871	$321,120,295	$328,792,030	$329,527,820	$319,557,546	$292,809,745	$226,935,661	$227,222,880	$3,303,705,908
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs	$0	$0	$0	$20,622	$21,401	$28,231	$33,672	$32,288	$30,904	$33,672	$30,904	$32,288	$263,980
14	Variable Power Plant O&M Costs over 514,000 MW Threshold (Per A6)	$0	$0	$364,700	$315,395	$227,805	$125,549	$98,150	$113,250	$52,850	$60,400	$151,000	$286,900	$1,795,999
15	Total	$0	$0	$364,700	$336,017	$249,206	$153,780	$131,822	$145,538	$83,754	$94,072	$181,904	$319,188	$2,059,979
16	**Adjustments to Fuel Cost**													
17	Sales to City of Key West (CKW)	($664,908)	($570,246)	($522,829)	($597,082)	($689,211)	($801,246)	$0	$0	$0	$0	$0	$0	($3,845,522)
18	Energy Imbalance Fuel Revenues	$56,481	$82,535	$48,854	$75,548	$65,257	$47,061	$0	$0	$0	$0	$0	$0	$375,736
19	Inventory Adjustments	($106,047)	($4,083,681)	$168,325	($88,560)	($285,132)	($28,899)	$0	$0	$0	$0	$0	$0	($4,423,994)
20	Non Recoverable Oil/Tank Bottoms	$0	($718,392)	$452,505	$0	$189	($189)	$0	$0	$0	$0	$0	$0	($265,887)
21	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,013	$287,849,940	$299,311,180	$320,490,802	$328,923,851	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,297,606,220
22	**Jurisdictional kWh Sales**													
23	Jurisdictional kWh Sales	7,684,412,091	7,108,916,875	6,977,292,798	7,671,972,198	8,616,263,762	9,110,063,405	10,150,088,249	10,080,997,264	9,763,403,645	9,104,618,770	8,255,228,566	8,067,004,659	102,590,262,282
24	Sale for Resale (excluding CKW) [2]	148,696,550	152,935,981	143,064,345	153,595,635	171,792,467	176,313,367	191,752,025	209,487,317	208,827,684	192,550,041	174,526,607	149,677,379	2,073,219,398
25	Sub-Total Sales (excluding CKW)	7,833,108,641	7,261,852,856	7,120,357,143	7,825,567,833	8,788,056,229	9,286,376,772	10,341,840,274	10,290,484,581	9,972,231,329	9,297,168,811	8,429,755,173	8,216,682,038	104,663,481,680
26														
27	**Jurisdictional % of Total Sales (Line 23/25)**	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.14586%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01916%
28	**True-up Calculation**													
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$235,363,510	$216,081,517	$211,924,637	$229,504,273	$251,555,289	$267,491,971	$299,212,015	$297,175,299	$287,813,033	$268,392,872	$243,353,902	$237,805,294	$3,045,673,611
30	**Fuel Adjustment Revenues Not Applicable to Period**													
31	Prior Period True-up (Collected)/Refunded This Period [3]	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$48,085,296
32	GPIF, Net of Revenue Taxes [4]	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,531)	($641,531)	($641,531)	($641,531)	($641,531)	($641,531)	($7,698,365)
33	Jurisdictional Fuel Revenues Applicable to Period	$238,729,088	$219,447,095	$215,290,215	$232,869,851	$254,920,867	$270,857,549	$302,577,593	$300,540,876	$291,178,610	$271,758,449	$246,719,479	$241,170,871	$3,086,060,542
34	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,013	$287,849,940	$299,311,180	$320,490,802	$328,923,851	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,297,606,220
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.14586%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01916%
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$221,888,753	$199,492,191	$230,007,841	$282,428,776	$293,697,828	$314,660,568	$323,086,631	$323,223,665	$313,201,211	$287,069,941	$222,595,570	$223,578,045	$3,234,931,021
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	$16,840,334	$19,954,904	($14,717,626)	($49,558,925)	($38,776,961)	($43,803,020)	($20,509,038)	($22,682,789)	($22,022,601)	($15,311,492)	$24,123,908	$17,592,827	($148,870,479)
38	Interest Provision for the Month	$2,912	$5,096	$4,722	$1,789	($1,335)	($3,612)	($5,141)	($6,421)	($7,740)	($8,874)	($8,854)	($8,012)	($35,469)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$60,921,435	$76,874,326	$58,154,314	$4,590,070	($38,195,333)	($86,009,073)	($110,530,361)	($137,226,679)	($163,264,127)	($182,591,601)	($162,483,655)	$48,085,296
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [5]	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)
41	Prior Period True-up Collected/(Refunded) This Period [3]	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($48,085,296)
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	$56,370,780	$72,323,673	$53,603,660	$39,416	($42,745,988)	($90,559,727)	($115,081,014)	($141,777,333)	($167,814,782)	($187,142,255)	($167,034,309)	($153,456,602)	($153,456,602)
43														

44 [1] January through June actuals include various adjustments as noted on the A-Schedules.

45 [2] Billed KWH includes all wholesale customers except CKW.

46 [3] Prior Period 2011/2012 True-up.

47 [4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.

48 [5] Deferred 2012 Final True-up.

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) Revenue/Cost Variance Analysis Schedule	(2) ACTUAL/ESTIMATED	(3) ORIGINAL PROJECTION	(4) Difference
1	**Jurisdictional Fuel Revenues**			
2	Revenues	$3,045,673,611	$3,102,901,635	($57,228,024)
3	MWH	102,590,262	103,200,444	(610,182)
4	$ per MWH	29.68775	30.06675	(0.37900)
5				
6	Variance due to Consumption			($18,346,188)
7	Variance due to Cost			($38,881,836)
8	Total Variance			($57,228,024)
9				
10	**Jurisdictional Total Fuel Costs**			
11	Costs	$3,234,931,021	$3,143,288,566	$91,642,455
12	MWH	102,590,262	103,200,444	(610,182)
13	$ per MWH	31.53253	30.45809	1.07444
14				
15	Variance due to Consumption			($18,584,980)
16	Variance due to Cost			$110,227,434
17	Total Variance			$91,642,455
18				
19	**Total Variance**			
20	Variance due to Consumption			$238,791
21	Variance due to Cost			($149,109,270)
22	Total Variance			($148,870,479)
23	Interest			($35,469)
24	Prior Year True-up			($4,550,654)
25	Total True-up			($153,456,602)
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL/ESTIMATED vs. ORIGINAL PROJECTION
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) FCR - 2013 Actual Estimated	(3) FCR - 2013 Original Projection - Jun - Dec	(4) Dif. FCR - 2013 Original Projection - Jun - Dec	(5) % Dif. FCR - 2013 Original Projection - Jun - Dec
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3) [1]	$3,082,868,833	$2,836,155,287	$246,713,546	8.7%
3	Nuclear Fuel Disposal Costs (Per A2)	$23,793,433	$24,785,825	($992,393)	(4.0%)
4	Scherer Coal Cars Depreciation & Return	($100,444)	$0	($100,444)	N/A
5	Fuel Cost of Power Sold (Per A6)	($56,324,203)	($20,692,255)	($35,631,948)	172.2%
6	Gains from Off-System Sales (Per A6)	($11,206,639)	($4,238,116)	($6,968,523)	164.4%
7	Fuel Cost of Purchased Power (Per A7)	$155,005,864	$186,831,284	($31,825,420)	(17.0%)
8	Energy Payments to Qualifying Facilities (Per A8)	$103,986,176	$143,346,388	($39,360,212)	(27.5%)
9	Energy Cost of Economy Purchases (Per A9)	$5,682,889	$42,063,927	($36,381,038)	(86.5%)
10	Total Fuel Costs & Net Power Transactions	$3,303,705,908	$3,208,252,341	$95,453,568	3.0%
11					
12	**Incremental Optimization Costs**				
13	Incremental Personnel, Software, and Hardware Costs	$263,980	$0	$263,980	N/A
14	Variable Power Plant O&M Costs over 514,000 MW Threshold (Per A6)	$1,795,999	$0	$1,795,999	N/A
15	Total	$2,059,979	$0	$2,059,979	N/A
16	**Adjustments to Fuel Cost**				
17	Sales to City of Key West (CKW)	($3,845,522)	($3,946,028)	$100,506	(2.5%)
18	Energy Imbalance Fuel Revenues	$375,736	$0	$375,736	N/A
19	Inventory Adjustments	($4,423,994)	$0	($4,423,994)	N/A
20	Non Recoverable Oil/Tank Bottoms	($265,887)	$0	($265,887)	N/A
21	Adjusted Total Fuel Costs & Net Power Transactions	$3,297,606,220	$3,204,306,313	$93,299,907	2.9%
22	**Jurisdictional kWh Sales**				
23	Jurisdictional kWh Sales	102,590,262,282	103,200,444,298	(610,182,016)	(0.6%)
24	Sale for Resale (excluding CKW) [2]	2,073,219,398	2,099,817,776	(26,598,378)	(1.3%)
25	Sub-Total Sales (excluding CKW)	104,663,481,680	105,300,262,074	(636,780,394)	(0.6%)
26					
27	**Jurisdictional % of Total Sales (Line 23/25)**	N/A	N/A	N/A	N/A
28	**True-up Calculation**				
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,045,673,611	$3,102,901,635	($57,228,024)	(1.8%)
30	**Fuel Adjustment Revenues Not Applicable to Period**				
31	Prior Period True-up (Collected)/Refunded This Period [3]	$48,085,296	$48,085,296	$0	0.0%
32	GPIF, Net of Revenue Taxes [4]	($7,698,365)	($7,698,365)	$0	(0.0%)
33	Jurisdictional Fuel Revenues Applicable to Period	$3,086,060,542	$3,143,288,566	($57,228,024)	(1.8%)
34	Adjusted Total Fuel Costs & Net Power Transactions	$3,297,606,220	$3,204,306,313	$93,299,907	2.9%
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	N/A	N/A	N/A	N/A
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$3,234,931,021	$3,143,288,566	$91,642,455	2.9%
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	($148,870,479)	$0	($148,870,479)	N/A
38	Interest Provision for the Month	($35,469)	$0	($35,469)	N/A
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$48,085,296	$0	0.0%
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [5]	($4,550,654)	$0	($4,550,654)	N/A
41	Prior Period True-up Collected/(Refunded) This Period [3]	($48,085,296)	($48,085,296)	$0	0.0%
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	($153,456,602)	$0	($153,456,602)	0.0%
43					

44 [1] January through June actuals include various adjustments as noted on the A-Schedules.
45 [2] Billed KWH includes all wholesale customers except CKW.
46 [3] Prior Period 2011/2012 True-up.
47 [4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.
48 [5] Deferred 2012 Final True-up.

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Fuel Cost of System Net Generation ($)													
2	Heavy Oil	175,248	186,272	675,248	1,879,167	1,003,094	2,077,583	11,478,041	14,834,877	25,791,995	7,743,199	3,485,913	0	69,330,637
3	Light Oil	251,735	385,253	1,980,262	819,242	1,436,080	643,242	1,319,040	1,219,949	1,679,321	172,655	442,783	0	10,349,563
4	Coal	14,022,984	12,321,270	13,281,549	14,446,074	11,447,914	16,062,546	13,498,000	12,623,100	12,978,900	11,968,900	11,262,900	10,358,700	154,272,836
5	Gas	192,662,133	185,486,609	210,891,468	236,851,196	242,398,178	257,113,182	253,719,552	253,145,418	227,446,256	233,259,354	180,876,975	189,909,498	2,663,759,820
6	Nuclear	12,925,680	9,671,348	7,804,464	13,220,456	14,674,532	16,534,210	19,582,400	19,582,400	18,781,300	14,330,800	18,453,900	19,594,200	185,155,690
7	**Total Fuel Cost of System Net Generation ($)**	220,037,780	208,050,752	234,632,991	267,216,135	270,959,798	292,430,763	299,597,033	301,405,743	286,677,773	267,474,908	214,522,470	219,862,398	3,082,868,545
8														
9	System Net Generation (MWH)													
10	Heavy Oil	(1,808)	478	3,369	11,065	5,173	12,646	71,698	96,168	166,016	50,008	21,904	0	436,717
11	Light Oil	1,611	2,232	12,026	5,254	8,529	4,445	3,478	3,411	4,625	584	1,179	0	47,374
12	Coal	510,895	433,608	492,845	517,541	409,849	513,860	507,361	471,101	487,647	448,460	429,825	392,328	5,615,319
13	Gas	5,472,419	5,580,054	6,216,826	6,179,442	6,450,621	6,774,561	7,415,511	7,495,878	6,616,348	6,925,212	5,170,684	5,398,736	75,696,293
14	Nuclear	1,988,376	1,513,557	1,216,458	1,941,110	2,144,047	2,409,561	2,501,181	2,501,181	2,397,542	1,789,559	2,413,967	2,567,188	25,383,727
15	Solar	4,495	4,975	6,976	6,353	7,233	5,860	18,954	17,826	15,611	14,225	9,132	7,915	119,555
16	**Total System Net Generation (MWH)**	7,975,989	7,534,903	7,948,500	8,660,765	9,025,452	9,720,933	10,518,183	10,585,565	9,687,789	9,228,048	8,046,691	8,366,167	107,298,985
17														
18	Units of Fuel Burned (Unit) [a]													
19	Heavy Oil	1,952	1,966	7,126	20,217	10,864	22,347	116,455	157,007	275,152	83,186	37,337	0	733,609
20	Light Oil	2,224	3,676	15,757	6,850	12,084	5,876	11,052	10,180	13,938	1,433	3,675	0	86,745
21	Coal [b]	53,239	43,028	32,203	44,860	44,860	73,525	60,168	57,219	56,474	50,828	40,533	39,205	596,142
22	Gas	39,361,833	39,766,367	43,503,736	46,454,547	47,200,994	50,409,689	52,395,885	53,075,883	47,023,895	48,591,932	35,761,121	36,985,563	540,531,444
23	Nuclear	20,147,225	15,616,107	12,640,147	20,859,112	22,905,284	24,990,594	27,094,244	27,094,244	25,977,833	19,579,677	25,508,266	27,109,985	269,522,718
24	**Total Units of Fuel Burned (Unit)**													
25														
26	BTU Burned (MMBTU)													
27	Heavy Oil	12,443	12,527	45,414	129,147	69,089	142,278	745,307	1,004,842	1,760,971	532,392	238,957	0	4,693,368
28	Light Oil	12,857	21,250	90,722	39,545	70,007	34,097	64,434	59,348	81,257	8,353	21,427	0	503,298
29	Coal	5,157,669	4,534,830	5,186,087	5,398,841	4,083,642	5,849,037	5,179,619	4,818,901	4,985,251	4,606,534	4,410,244	4,032,742	58,243,399
30	Gas	39,936,356	40,305,984	44,131,313	47,087,749	47,880,284	51,119,304	52,395,885	53,075,883	47,023,895	48,591,932	35,761,121	36,985,563	544,295,269
31	Nuclear	20,147,225	15,616,107	12,640,147	20,859,112	22,905,284	24,990,594	27,094,244	27,094,244	25,977,833	19,579,677	25,508,266	27,109,985	269,522,718
32	**Total BTU Burned (MMBTU)**	65,266,550	60,490,699	62,093,684	73,514,395	75,008,307	82,135,311	85,479,489	86,053,218	79,829,207	73,318,888	65,940,015	68,128,290	877,258,052
33														
34	Fuel Cost per Unit ($/Unit)													
35	Heavy Oil	89.7788	94.7468	94.7583	92.9499	92.3320	92.9692	98.5620	94.4854	93.7373	93.0830	93.3635	0.0000	94.5063
36	Light Oil	113.1903	104.8022	125.6751	119.5974	118.8414	109.4694	119.3485	119.8378	120.4851	120.4851	120.4851	0.0000	119.3102
37	Coal	78.8383	79.0800	80.0861	78.0173	78.0173	73.6463	76.9412	76.9779	76.9044	77.2330	77.2334	77.1738	77.2506
38	Gas	4.8946	4.6644	4.8477	5.0986	5.1354	5.1005	4.8424	4.7695	4.8368	4.8004	5.0579	5.1347	4.9280
39	Nuclear	0.6416	0.6193	0.6174	0.6338	0.6407	0.6616	0.7228	0.7228	0.7230	0.7319	0.7234	0.7228	0.6870
40	**Total Fuel Cost per Unit ($/Unit)**													
41														

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	**Generation Mix (%)**													
2	Heavy Oil	(0.02%)	0.01%	0.04%	0.13%	0.06%	0.13%	0.68%	0.91%	1.71%	0.54%	0.27%	0.00%	0.41%
3	Light Oil	0.02%	0.03%	0.15%	0.06%	0.09%	0.05%	0.03%	0.03%	0.05%	0.01%	0.01%	0.00%	0.04%
4	Coal	6.41%	5.75%	6.20%	5.98%	4.54%	5.29%	4.82%	4.45%	5.03%	4.86%	5.34%	4.69%	5.23%
5	Gas	68.61%	74.06%	78.21%	71.35%	71.47%	69.69%	70.50%	70.81%	68.30%	75.05%	64.26%	64.53%	70.55%
6	Nuclear	24.93%	20.09%	15.30%	22.41%	23.76%	24.79%	23.78%	23.63%	24.75%	19.39%	30.00%	30.69%	23.66%
7	Solar	0.06%	0.07%	0.09%	0.07%	0.08%	0.06%	0.18%	0.17%	0.16%	0.15%	0.11%	0.09%	0.11%
8	**Total Generation Mix (%)**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
9														
10	**Fuel Cost per MMBTU ($/MMBTU)**													
11	Heavy Oil	14.0839	14.8693	14.8687	14.5506	14.5188	14.6023	15.4004	14.7634	14.6465	14.5442	14.5880	0.0000	14.7720
12	Light Oil	19.5803	18.1296	21.8277	20.7166	20.5133	18.8650	20.4712	20.5558	20.6668	20.6698	20.6647	0.0000	20.5635
13	Coal	2.7189	2.7170	2.5610	2.6758	2.8034	2.7462	2.6060	2.6195	2.6035	2.5982	2.5538	2.5686	2.6488
14	Gas	4.8242	4.6020	4.7787	5.0300	5.0626	5.0297	4.8424	4.7695	4.8368	4.8004	5.0579	5.1347	4.8940
15	Nuclear	0.6416	0.6193	0.6174	0.6338	0.6407	0.6616	0.7228	0.7228	0.7230	0.7319	0.7234	0.7228	0.6870
16														
17	**BTU Burned per KWH (BTU/KWH)**													
18	Heavy Oil	(6,883)	26,211	13,481	11,671	13,356	11,251	10,395	10,449	10,607	10,646	10,909	0	10,747
19	Light Oil	7,978	9,522	7,544	7,527	8,208	7,670	18,526	17,399	17,569	14,303	18,174	0	10,624
20	Coal	10,095	10,458	10,523	10,432	9,964	11,383	10,209	10,229	10,223	10,272	10,261	10,279	10,372
21	Gas	7,298	7,223	7,099	7,620	7,423	7,546	7,066	7,081	7,107	7,017	6,916	6,851	7,191
22	Nuclear	10,133	10,317	10,391	10,746	10,683	10,371	10,833	10,833	10,835	10,941	10,567	10,560	10,618
23														
24	**Generated Fuel Cost per KWH (cents/KWH)**													
25	Heavy Oil	(9.6942)	38.9740	20.0448	16.9824	19.3916	16.4285	16.0089	15.4260	15.5358	15.4839	15.9145	0.0000	15.8754
26	Light Oil	15.6218	17.2625	16.4668	15.5930	16.8377	14.4701	37.9252	35.7651	36.3096	29.5642	37.5558	0.0000	21.8464
27	Coal	2.7448	2.8416	2.6949	2.7913	2.7932	3.1259	2.6604	2.6795	2.6615	2.6689	2.6203	2.6403	2.7474
28	Gas	3.5206	3.3241	3.3923	3.8329	3.7577	3.7953	3.4215	3.3771	3.4376	3.3683	3.4981	3.5177	3.5190
29	Nuclear	0.6501	0.6390	0.6416	0.6811	0.6844	0.6862	0.7829	0.7829	0.7834	0.8008	0.7645	0.7633	0.7294
30	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.7588	2.7612	2.9519	3.0854	3.0022	3.0083	2.8484	2.8473	2.9592	2.8985	2.6660	2.6280	2.8732
31														
32														
33	[a] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
34	[b] Scherer coal is not reported in Tons, excludes Scherer coal													
35														
36														
37														
38														
39														
40														
41														

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jul - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		813,641					5,357,824	1,000,000	5,357,824	25,476,171	3.13	4.75
5	Plant Unit Info	1,210	813,641	90.4%	94.7%	90.4%	6,585			5,357,824	25,476,171	3.13	
6	*Desoto Solar*												
7	Solar		5,118					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,118	27.5%		27.5%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		3,478					11,052	5,830,076	64,434	1,319,040	37.93	119.35
15	Plant Unit Info	648	3,478	0.7%	93.5%	35.8%	18,526			64,434	1,319,040	37.93	
16	*Fort Myers 2*												
17	Gas		571,383					4,093,583	1,000,000	4,093,583	19,710,804	3.45	4.82
18	Plant Unit Info	1,349	571,383	56.9%	94.2%	94.8%	7,164			4,093,583	19,710,804	3.45	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		30,608					335,418	1,000,000	335,418	1,663,245	5.43	4.96
22	Plant Unit Info	296	30,608	27.8%	95.1%	98.1%	10,958			335,418	1,663,245	5.43	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		802					13,373	1,000,000	13,373	66,893	8.34	5.00
26	Plant Unit Info	684	802	0.2%	93.5%	58.6%	16,681			13,373	66,893	8.34	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		89,940					736,327	1,000,000	736,327	3,666,759	4.08	4.98
30	Plant Unit Info	438	89,940	27.6%	94.6%	94.6%	8,187			736,327	3,666,759	4.08	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		99,821					816,477	1,000,000	816,477	4,066,132	4.07	4.98
34	Plant Unit Info	438	99,821	30.6%	94.1%	94.6%	8,179			816,477	4,066,132	4.07	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	0	0.0%	0.0%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		32,900					58,502	6,399,952	374,410	5,772,718	17.55	98.68
4	Gas		22,141					227,822	1,000,000	227,822	1,140,228	5.15	5.00
5	Plant Unit Info	788	55,041	9.4%	95.0%	67.2%	10,941			602,232	6,912,945	12.56	
6	*Manatee 3*												
7	Gas		724,543					4,965,805	1,000,000	4,965,805	24,049,728	3.32	4.84
8	Plant Unit Info	1,058	724,543	92.1%	94.9%	92.0%	6,854			4,965,805	24,049,728	3.32	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		28,505					42,476	6,399,920	271,843	4,147,239	14.55	97.64
15	Gas		71,454					803,494	1,000,000	803,494	3,989,806	5.58	4.97
16	Plant Unit Info	802	99,959	16.8%	95.0%	62.6%	10,758			1,075,337	8,137,045	8.14	
17	*Martin 3*												
18	Gas		113,991					852,460	1,000,000	852,460	4,101,615	3.60	4.81
19	Plant Unit Info	431	113,991	35.6%	94.3%	94.8%	7,478			852,460	4,101,615	3.60	
20	*Martin 4*												
21	Gas		127,848					950,250	1,000,000	950,250	4,572,199	3.58	4.81
22	Plant Unit Info	431	127,848	39.9%	94.8%	94.8%	7,433			950,250	4,572,199	3.58	
23	*Martin 8*												
24	Gas		666,633					4,670,255	1,000,000	4,670,255	22,559,325	3.38	4.83
25	Plant Unit Info	1,052	666,633	85.2%	94.9%	92.4%	7,006			4,670,255	22,559,325	3.38	
26	*Martin 8 Solar*												
27	Solar		12,062					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	12,062	21.6%		21.6%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		44,514					399,414	1,000,000	399,414	1,985,906	4.46	4.97
32	Plant Unit Info	239	44,514	25.0%	95.0%	95.0%	8,973			399,414	1,985,906	4.46	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		43,833					394,257	1,000,000	394,257	1,956,551	4.46	4.96
36	Plant Unit Info	239	43,833	24.7%	94.4%	95.0%	8,995			394,257	1,956,551	4.46	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		522,818					3,694,662	1,000,000	3,694,662	17,823,762	3.41	4.82
2	Plant Unit Info	905	522,818	77.7%	95.8%	97.7%	7,067			3,694,662	17,823,762	3.41	
3	*Sanford 5*												
4	Gas		362,203					2,622,195	1,000,000	2,622,195	12,635,478	3.49	4.82
5	Plant Unit Info	901	362,203	54.0%	89.4%	89.5%	7,240			2,622,195	12,635,478	3.49	
6	*Scherer 4*												
7	Coal		376,675					226,818	17,000,022	3,855,911	8,868,600	2.35	39.10
8	Plant Unit Info	629	376,675	80.5%	93.8%	91.8%	10,237			3,855,911	8,868,600	2.35	
9	*St Johns 1O*												
10	Coal		63,939					29,598	22,000,135	651,160	2,277,300	3.56	76.94
11	Plant Unit Info	124	63,939	69.3%	94.1%	69.3%	10,184			651,160	2,277,300	3.56	
12	*St Johns 2O*												
13	Coal		66,747					30,570	22,000,262	672,548	2,352,100	3.52	76.94
14	Plant Unit Info	124	66,747	72.4%	94.0%	72.3%	10,076			672,548	2,352,100	3.52	
15	*St Lucie 1*												
16	Nuclear		711,622					7,514,567	1,000,000	7,514,567	5,251,600	0.74	0.70
17	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	5,251,600	0.74	
18	*St Lucie 2*												
19	Nuclear		609,333					6,369,659	1,000,000	6,369,659	4,568,800	0.75	0.72
20	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	4,568,800	0.75	
21	*Space Coast*												
22	Solar		1,774					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,774	23.9%		23.9%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		10,293					15,477	6,400,078	99,054	1,558,084	15.14	100.67
26	Gas		27,285					289,195	1,000,000	289,195	1,442,719	5.29	4.99
27	Plant Unit Info	378	37,578	13.4%	94.5%	80.8%	10,332			388,249	3,000,803	7.99	
28	*Turkey Point 3*												
29	Nuclear		586,125					6,560,405	1,000,000	6,560,405	5,120,200	0.87	0.78
30	Plant Unit Info	808	586,125	97.5%	97.8%	97.5%	11,193			6,560,405	5,120,200	0.87	
31	*Turkey Point 4*												
32	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,641,800	0.78	0.70
33	Plant Unit Info	819	594,101	97.5%	98.0%	97.5%	11,193			6,649,613	4,641,800	0.78	
34	*Turkey Point 5*												
35	Gas		625,451					4,348,502	1,000,000	4,348,502	21,217,048	3.39	4.88
36	Plant Unit Info	1,053	625,451	79.8%	85.7%	84.0%	6,953			4,348,502	21,217,048	3.39	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		806,204					5,551,013	1,000,000	5,551,013	27,063,187	3.36	4.88
2	Plant Unit Info	1,219	806,204	88.9%	94.7%	88.9%	6,885			5,551,013	27,063,187	3.36	
3	*WCEC 02*												
4	Gas		814,466					5,608,966	1,000,000	5,608,966	27,509,258	3.38	4.90
5	Plant Unit Info	1,219	814,466	89.8%	94.7%	89.8%	6,887			5,608,966	27,509,258	3.38	
6	*WCEC 03*												
7	Gas		835,934					5,664,595	1,000,000	5,664,595	27,022,740	3.23	4.77
8	Plant Unit Info	1,219	835,934	92.2%	94.4%	92.2%	6,776			5,664,595	27,022,740	3.23	
9	**System Totals**												
10	Plant Unit Info	23,364	10,518,183				8,127			85,479,489	299,597,033	2.85	
11													
12													
13													
14													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Aug - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		825,520					5,432,642	1,000,000	5,432,642	25,331,539	3.07	4.66
5	Plant Unit Info	1,210	825,520	91.7%	94.7%	91.7%	6,581			5,432,642	25,331,539	3.07	
6	*Desoto Solar*												
7	Solar		4,864					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,864	26.2%		26.2%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		3,411					10,180	5,829,862	59,348	1,219,949	35.77	119.84
15	Plant Unit Info	648	3,411	0.7%	93.5%	29.2%	17,399			59,348	1,219,949	35.77	
16	*Fort Myers 2*												
17	Gas		619,611					4,426,031	1,000,000	4,426,031	21,000,221	3.39	4.74
18	Plant Unit Info	1,349	619,611	61.7%	94.2%	93.9%	7,143			4,426,031	21,000,221	3.39	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		29,303					321,504	1,000,000	321,504	1,573,646	5.37	4.89
22	Plant Unit Info	296	29,303	26.6%	95.1%	98.1%	10,972			321,504	1,573,646	5.37	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		2,387					37,134	1,000,000	37,134	184,082	7.71	4.96
26	Plant Unit Info	684	2,387	0.5%	93.5%	87.2%	15,557			37,134	184,082	7.71	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		109,689					895,535	1,000,000	895,535	4,410,502	4.02	4.92
30	Plant Unit Info	438	109,689	33.7%	94.6%	94.5%	8,164			895,535	4,410,502	4.02	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		126,971					1,035,223	1,000,000	1,035,223	5,108,221	4.02	4.93
34	Plant Unit Info	438	126,971	39.0%	94.1%	94.4%	8,153			1,035,223	5,108,221	4.02	
35	*Manatee 1*												
36	Heavy Oil		27,149					47,238	6,399,953	302,321	4,460,965	16.43	94.44
37	Gas		18,099					186,425	1,000,000	186,425	924,167	5.11	4.96

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	45,248	7.7%	59.4%	79.8%	10,801			488,746	5,385,132	11.90	
2	*Manatee 2*												
3	Heavy Oil		28,470					49,291	6,399,951	315,460	4,654,877	16.35	94.44
4	Gas		19,187					197,757	1,000,000	197,757	981,275	5.11	4.96
5	Plant Unit Info	788	47,657	8.1%	95.0%	81.7%	10,769			513,217	5,636,152	11.83	
6	*Manatee 3*												
7	Gas		729,091					4,994,304	1,000,000	4,994,304	23,743,480	3.26	4.75
8	Plant Unit Info	1,058	729,091	92.6%	94.9%	92.6%	6,850			4,994,304	23,743,480	3.26	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		26,127					38,797	6,400,082	248,304	3,610,750	13.82	93.07
15	Gas		64,475					727,390	1,000,000	727,390	3,581,837	5.56	4.92
16	Plant Unit Info	802	90,602	15.2%	95.0%	58.8%	10,769			975,694	7,192,587	7.94	
17	*Martin 3*												
18	Gas		133,193					991,887	1,000,000	991,887	4,703,196	3.53	4.74
19	Plant Unit Info	431	133,193	41.5%	94.3%	94.8%	7,447			991,887	4,703,196	3.53	
20	*Martin 4*												
21	Gas		133,158					988,688	1,000,000	988,688	4,687,975	3.52	4.74
22	Plant Unit Info	431	133,158	41.5%	94.8%	94.8%	7,425			988,688	4,687,975	3.52	
23	*Martin 8*												
24	Gas		677,626					4,739,668	1,000,000	4,739,668	22,512,947	3.32	4.75
25	Plant Unit Info	1,052	677,626	86.6%	94.9%	92.9%	6,995			4,739,668	22,512,947	3.32	
26	*Martin 8 Solar*												
27	Solar		11,278					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	11,278	20.2%		20.2%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		47,012					421,156	1,000,000	421,156	2,069,962	4.40	4.91
32	Plant Unit Info	239	47,012	26.4%	95.0%	95.0%	8,958			421,156	2,069,962	4.40	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		46,331					416,044	1,000,000	416,044	2,035,916	4.39	4.89
36	Plant Unit Info	239	46,331	26.1%	94.4%	95.0%	8,980			416,044	2,035,916	4.39	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		547,338					3,858,615	1,000,000	3,858,615	18,322,824	3.35	4.75
2	Plant Unit Info	905	547,338	81.3%	95.8%	98.3%	7,050			3,858,615	18,322,824	3.35	
3	*Sanford 5*												
4	Gas		295,456					2,178,745	1,000,000	2,178,745	10,339,862	3.50	4.75
5	Plant Unit Info	901	295,456	44.1%	81.8%	83.4%	7,374			2,178,745	10,339,862	3.50	
6	*Scherer 4*												
7	Coal		347,643					209,417	17,000,010	3,560,091	8,218,500	2.36	39.24
8	Plant Unit Info	629	347,643	74.3%	93.8%	90.8%	10,241			3,560,091	8,218,500	2.36	
9	*St Johns 1O*												
10	Coal		58,406					27,353	22,000,073	601,768	2,105,600	3.61	76.98
11	Plant Unit Info	124	58,406	63.3%	94.1%	63.3%	10,303			601,768	2,105,600	3.61	
12	*St Johns 2O*												
13	Coal		65,052					29,866	21,999,665	657,042	2,299,000	3.53	76.98
14	Plant Unit Info	124	65,052	70.5%	94.0%	70.5%	10,100			657,042	2,299,000	3.53	
15	*St Lucie 1*												
16	Nuclear		711,622					7,514,567	1,000,000	7,514,567	5,251,600	0.74	0.70
17	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	5,251,600	0.74	
18	*St Lucie 2*												
19	Nuclear		609,333					6,369,659	1,000,000	6,369,659	4,568,800	0.75	0.72
20	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	4,568,800	0.75	
21	*Space Coast*												
22	Solar		1,684					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,684	22.6%		22.6%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		14,422					21,681	6,399,935	138,757	2,108,284	14.62	97.24
26	Gas		31,572					335,134	1,000,000	335,134	1,657,467	5.25	4.95
27	Plant Unit Info	378	45,994	16.4%	94.5%	80.1%	10,303			473,891	3,765,750	8.19	
28	*Turkey Point 3*												
29	Nuclear		586,125					6,560,405	1,000,000	6,560,405	5,120,200	0.87	0.78
30	Plant Unit Info	808	586,125	97.5%	97.8%	97.5%	11,193			6,560,405	5,120,200	0.87	
31	*Turkey Point 4*												
32	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,641,800	0.78	0.70
33	Plant Unit Info	819	594,101	97.5%	98.0%	97.5%	11,193			6,649,613	4,641,800	0.78	
34	*Turkey Point 5*												
35	Gas		572,984					3,993,957	1,000,000	3,993,957	19,160,368	3.34	4.80
36	Plant Unit Info	1,053	572,984	73.1%	82.6%	82.8%	6,970			3,993,957	19,160,368	3.34	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		811,664					5,588,350	1,000,000	5,588,350	26,886,284	3.31	4.81
2	Plant Unit Info	1,219	811,664	89.5%	94.7%	89.5%	6,885			5,588,350	26,886,284	3.31	
3	*WCEC 02*												
4	Gas		817,923					5,634,468	1,000,000	5,634,468	27,343,810	3.34	4.85
5	Plant Unit Info	1,219	817,923	90.2%	94.7%	90.2%	6,889			5,634,468	27,343,810	3.34	
6	*WCEC 03*												
7	Gas		837,290					5,675,225	1,000,000	5,675,225	26,585,838	3.18	4.68
8	Plant Unit Info	1,219	837,290	92.3%	94.4%	92.3%	6,778			5,675,225	26,585,838	3.18	
9	**System Totals**												
10	Plant Unit Info	23,364	10,585,565				8,129			86,053,218	301,405,743	2.85	
11													
12													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Sep - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		799,314					5,261,193	1,000,000	5,261,193	25,036,797	3.13	4.76
5	Plant Unit Info	1,210	799,314	91.8%	94.7%	91.7%	6,582			5,261,193	25,036,797	3.13	
6	*Desoto Solar*												
7	Solar		4,325					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,325	24.0%		24.0%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		4,625					13,938	5,829,890	81,257	1,679,321	36.31	120.49
15	Plant Unit Info	648	4,625	1.0%	93.5%	29.7%	17,569			81,257	1,679,321	36.31	
16	*Fort Myers 2*												
17	Gas		116,600					880,297	1,000,000	880,297	4,258,867	3.65	4.84
18	Plant Unit Info	1,349	116,600	12.0%	25.2%	54.0%	7,550			880,297	4,258,867	3.65	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		33,220					364,448	1,000,000	364,448	1,779,363	5.36	4.88
22	Plant Unit Info	296	33,220	31.2%	95.1%	98.1%	10,971			364,448	1,779,363	5.36	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		1,675					26,321	1,000,000	26,321	128,483	7.67	4.88
26	Plant Unit Info	684	1,675	0.3%	93.5%	81.6%	15,710			26,321	128,483	7.67	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		106,104					868,167	1,000,000	868,167	4,241,273	4.00	4.89
30	Plant Unit Info	438	106,104	33.7%	94.6%	94.6%	8,182			868,167	4,241,273	4.00	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		111,101					907,688	1,000,000	907,688	4,441,341	4.00	4.89
34	Plant Unit Info	438	111,101	35.2%	94.1%	94.6%	8,170			907,688	4,441,341	4.00	
35	*Manatee 1*												
36	Heavy Oil		59,142					102,069	6,400,004	653,242	9,601,219	16.23	94.07
37	Gas		39,428					406,870	1,000,000	406,870	2,000,460	5.07	4.92

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	98,570	17.4%	96.9%	83.4%	10,755			1,060,112	11,601,678	11.77	
2	*Manatee 2*												
3	Heavy Oil		58,212					100,688	6,399,988	644,402	9,419,286	16.18	93.55
4	Gas		39,222					404,953	1,000,000	404,953	1,996,927	5.09	4.93
5	Plant Unit Info	788	97,434	17.2%	95.0%	85.3%	10,770			1,049,355	11,416,214	11.72	
6	*Manatee 3*												
7	Gas		705,812					4,834,856	1,000,000	4,834,856	23,426,280	3.32	4.85
8	Plant Unit Info	1,058	705,812	92.7%	94.9%	92.7%	6,850			4,834,856	23,426,280	3.32	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		32,698					48,450	6,400,000	310,080	4,464,909	13.65	92.15
15	Gas		78,160					874,250	1,000,000	874,250	4,285,839	5.48	4.90
16	Plant Unit Info	802	110,858	19.2%	95.0%	62.3%	10,683			1,184,330	8,750,749	7.89	
17	*Martin 3*												
18	Gas		120,119					896,158	1,000,000	896,158	4,334,713	3.61	4.84
19	Plant Unit Info	431	120,119	38.7%	94.3%	94.8%	7,461			896,158	4,334,713	3.61	
20	*Martin 4*												
21	Gas		112,735					840,052	1,000,000	840,052	4,063,293	3.60	4.84
22	Plant Unit Info	431	112,735	36.3%	94.8%	94.8%	7,452			840,052	4,063,293	3.60	
23	*Martin 8*												
24	Gas		550,823					3,877,795	1,000,000	3,877,795	18,782,510	3.41	4.84
25	Plant Unit Info	1,052	550,823	72.7%	94.9%	93.7%	7,040			3,877,795	18,782,510	3.41	
26	*Martin 8 Solar*												
27	Solar		9,794					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	9,794	18.1%		18.1%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		51,327					460,712	1,000,000	460,712	2,249,361	4.38	4.88
32	Plant Unit Info	239	51,327	29.8%	95.0%	95.0%	8,976			460,712	2,249,361	4.38	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		26,459					281,037	1,000,000	281,037	1,371,966	5.19	4.88
36	Plant Unit Info	239	26,459	15.4%	53.6%	51.0%	10,622			281,037	1,371,966	5.19	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		384,510					2,747,634	1,000,000	2,747,634	13,294,958	3.46	4.84
2	Plant Unit Info	905	384,510	59.0%	95.8%	99.7%	7,146			2,747,634	13,294,958	3.46	
3	*Sanford 5*												
4	Gas		255,198					1,888,306	1,000,000	1,888,306	9,137,019	3.58	4.84
5	Plant Unit Info	901	255,198	39.3%	84.5%	84.8%	7,399			1,888,306	9,137,019	3.58	
6	*Scherer 4*												
7	Coal		365,534					220,167	16,999,991	3,742,837	8,635,800	2.36	39.22
8	Plant Unit Info	629	365,534	80.7%	93.8%	91.2%	10,239			3,742,837	8,635,800	2.36	
9	*St Johns 1O*												
10	Coal		58,485					27,299	21,999,890	600,575	2,099,400	3.59	76.90
11	Plant Unit Info	124	58,485	65.5%	94.1%	65.5%	10,269			600,575	2,099,400	3.59	
12	*St Johns 2O*												
13	Coal		63,628					29,175	21,999,623	641,839	2,243,700	3.53	76.90
14	Plant Unit Info	124	63,628	71.3%	94.0%	71.3%	10,087			641,839	2,243,700	3.53	
15	*St Lucie 1*												
16	Nuclear		665,710					7,029,762	1,000,000	7,029,762	4,912,800	0.74	0.70
17	Plant Unit Info	981	665,710	94.3%	94.3%	97.5%	10,560			7,029,762	4,912,800	0.74	
18	*St Lucie 2*												
19	Nuclear		589,677					6,164,182	1,000,000	6,164,182	4,421,400	0.75	0.72
20	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,453			6,164,182	4,421,400	0.75	
21	*Space Coast*												
22	Solar		1,492					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,492	20.7%		20.7%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		15,964					23,945	6,399,958	153,247	2,306,581	14.45	96.33
26	Gas		11,160					121,489	1,000,000	121,489	594,362	5.33	4.89
27	Plant Unit Info	378	27,124	10.0%	85.1%	89.7%	10,129			274,736	2,900,943	10.70	
28	*Turkey Point 3*												
29	Nuclear		567,218					6,348,776	1,000,000	6,348,776	4,955,000	0.87	0.78
30	Plant Unit Info	808	567,218	97.5%	97.8%	97.5%	11,193			6,348,776	4,955,000	0.87	
31	*Turkey Point 4*												
32	Nuclear		574,937					6,435,113	1,000,000	6,435,113	4,492,100	0.78	0.70
33	Plant Unit Info	819	574,937	97.5%	98.0%	97.5%	11,193			6,435,113	4,492,100	0.78	
34	*Turkey Point 5*												
35	Gas		684,949					4,718,934	1,000,000	4,718,934	22,945,112	3.35	4.86
36	Plant Unit Info	1,053	684,949	90.3%	94.9%	92.4%	6,889			4,718,934	22,945,112	3.35	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		785,325					5,408,174	1,000,000	5,408,174	26,239,421	3.34	4.85
2	Plant Unit Info	1,219	785,325	89.5%	94.7%	89.5%	6,887			5,408,174	26,239,421	3.34	
3	*WCEC 02*												
4	Gas		791,942					5,455,571	1,000,000	5,455,571	26,598,551	3.36	4.88
5	Plant Unit Info	1,219	791,942	90.2%	94.7%	90.2%	6,889			5,455,571	26,598,551	3.36	
6	*WCEC 03*												
7	Gas		811,166					5,498,992	1,000,000	5,498,992	26,239,360	3.23	4.77
8	Plant Unit Info	1,219	811,166	92.4%	94.4%	92.4%	6,779			5,498,992	26,239,360	3.23	
9	**System Totals**												
10	Plant Unit Info	23,364	9,687,789				8,240			79,829,207	286,677,773	2.96	
11													
12													
13													
14													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Oct - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		808,202					5,323,299	1,000,000	5,323,299	25,124,918	3.11	4.72
5	Plant Unit Info	1,210	808,202	89.8%	94.7%	89.8%	6,587			5,323,299	25,124,918	3.11	
6	*Desoto Solar*												
7	Solar		4,176					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,176	22.5%		22.5%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	342	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		584					1,433	5,829,030	8,353	172,655	29.56	120.49
15	Plant Unit Info	648	584	0.1%	93.5%	15.0%	14,303			8,353	172,655	29.56	
16	*Fort Myers 2*												
17	Gas		193,218					1,493,926	1,000,000	1,493,926	7,142,577	3.70	4.78
18	Plant Unit Info	1,349	193,218	19.3%	46.5%	46.1%	7,732			1,493,926	7,142,577	3.70	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		22,195					243,547	1,000,000	243,547	1,198,650	5.40	4.92
22	Plant Unit Info	296	22,195	20.2%	95.1%	98.1%	10,973			243,547	1,198,650	5.40	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	684	0	0.0%	93.5%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		82,714					677,195	1,000,000	677,195	3,331,345	4.03	4.92
30	Plant Unit Info	438	82,714	25.4%	94.6%	94.4%	8,187			677,195	3,331,345	4.03	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		90,735					741,615	1,000,000	741,615	3,654,274	4.03	4.93
34	Plant Unit Info	438	90,735	27.8%	94.1%	94.6%	8,173			741,615	3,654,274	4.03	
35	*Manatee 1*												
36	Heavy Oil		24,234					42,224	6,399,986	270,233	3,949,560	16.30	93.54
37	Gas		16,592					171,264	1,000,000	171,264	845,692	5.10	4.94

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	788	40,826	7.0%	96.9%	76.2%	10,814			441,497	4,795,253	11.75	
2	*Manatee 2*												
3	Heavy Oil		10,526					18,060	6,399,945	115,583	1,689,310	16.05	93.54
4	Gas		7,017					72,508	1,000,000	72,508	358,396	5.11	4.94
5	Plant Unit Info	788	17,543	3.0%	95.0%	92.8%	10,721			188,091	2,047,706	11.67	
6	*Manatee 3*												
7	Gas		725,855					4,973,463	1,000,000	4,973,463	23,900,893	3.29	4.81
8	Plant Unit Info	1,058	725,855	92.2%	94.9%	92.2%	6,852			4,973,463	23,900,893	3.29	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		15,248					22,902	6,400,140	146,576	2,104,328	13.80	91.88
15	Gas		39,665					464,342	1,000,000	464,342	2,279,303	5.75	4.91
16	Plant Unit Info	802	54,913	9.2%	95.0%	49.6%	11,125			610,918	4,383,632	7.98	
17	*Martin 3*												
18	Gas		75,177					560,241	1,000,000	560,241	2,678,374	3.56	4.78
19	Plant Unit Info	431	75,177	23.4%	54.8%	94.8%	7,452			560,241	2,678,374	3.56	
20	*Martin 4*												
21	Gas		110,693					822,068	1,000,000	822,068	3,930,185	3.55	4.78
22	Plant Unit Info	431	110,693	34.5%	94.8%	94.8%	7,427			822,068	3,930,185	3.55	
23	*Martin 8*												
24	Gas		667,402					4,667,863	1,000,000	4,667,863	22,393,320	3.36	4.80
25	Plant Unit Info	1,052	667,402	85.3%	94.9%	92.6%	6,994			4,667,863	22,393,320	3.36	
26	*Martin 8 Solar*												
27	Solar		8,611					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	8,611	15.4%		15.4%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		37,019					332,186	1,000,000	332,186	1,632,331	4.41	4.91
32	Plant Unit Info	239	37,019	20.8%	95.0%	95.0%	8,973			332,186	1,632,331	4.41	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		16,579					180,313	1,000,000	180,313	886,976	5.35	4.92
36	Plant Unit Info	239	16,579	9.3%	47.2%	47.5%	10,876			180,313	886,976	5.35	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		541,317					3,816,578	1,000,000	3,816,578	18,271,290	3.38	4.79
2	Plant Unit Info	905	541,317	80.4%	95.8%	97.9%	7,051			3,816,578	18,271,290	3.38	
3	*Sanford 5*												
4	Gas		356,448					2,558,560	1,000,000	2,558,560	12,254,873	3.44	4.79
5	Plant Unit Info	901	356,448	53.2%	94.8%	94.2%	7,178			2,558,560	12,254,873	3.44	
6	*Scherer 4*												
7	Coal		340,506					205,194	17,000,039	3,488,306	8,043,300	2.36	39.20
8	Plant Unit Info	629	340,506	72.8%	93.8%	89.5%	10,244			3,488,306	8,043,300	2.36	
9	*St Johns 1O*												
10	Coal		49,677					23,780	22,000,042	523,161	1,836,600	3.70	77.23
11	Plant Unit Info	124	49,677	53.9%	94.1%	53.8%	10,531			523,161	1,836,600	3.70	
12	*St Johns 2O*												
13	Coal		58,277					27,048	22,000,407	595,067	2,089,000	3.58	77.23
14	Plant Unit Info	124	58,277	63.2%	94.0%	63.2%	10,211			595,067	2,089,000	3.58	
15	*St Lucie 1*												
16	Nuclear		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	981	0	0.0%	0.0%	0.0%	0			0	0	0.00	
18	*St Lucie 2*												
19	Nuclear		609,333					6,369,659	1,000,000	6,369,659	4,568,800	0.75	0.72
20	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	4,568,800	0.75	
21	*Space Coast*												
22	Solar		1,438					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,438	19.3%		19.3%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	378	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Turkey Point 3*												
29	Nuclear		586,125					6,560,405	1,000,000	6,560,405	5,120,200	0.87	0.78
30	Plant Unit Info	808	586,125	97.5%	97.8%	97.5%	11,193			6,560,405	5,120,200	0.87	
31	*Turkey Point 4*												
32	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,641,800	0.78	0.70
33	Plant Unit Info	819	594,101	97.5%	98.0%	97.5%	11,193			6,649,613	4,641,800	0.78	
34	*Turkey Point 5*												
35	Gas		700,817					4,834,076	1,000,000	4,834,076	23,428,963	3.34	4.85
36	Plant Unit Info	1,053	700,817	89.5%	94.9%	91.5%	6,898			4,834,076	23,428,963	3.34	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Gas		793,263					5,458,612	1,000,000	5,458,612	26,338,334	3.32	4.83
2	Plant Unit Info	1,219	793,263	87.5%	94.7%	87.5%	6,881			5,458,612	26,338,334	3.32	
3	*WCEC 02*												
4	Gas		806,193					5,549,172	1,000,000	5,549,172	26,866,649	3.33	4.84
5	Plant Unit Info	1,219	806,193	88.9%	94.7%	88.9%	6,883			5,549,172	26,866,649	3.33	
6	*WCEC 03*												
7	Gas		834,112					5,651,106	1,000,000	5,651,106	26,742,011	3.21	4.73
8	Plant Unit Info	1,219	834,112	92.0%	94.4%	92.0%	6,775			5,651,106	26,742,011	3.21	
9	**System Totals**												
10	Plant Unit Info	23,364	9,228,048				7,945			73,318,888	267,474,908	2.90	
11													
12													
13													
14													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Nov - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		607,325					3,986,251	1,000,000	3,986,251	19,945,981	3.28	5.00
5	Plant Unit Info	1,355	607,325	62.3%	72.6%	82.4%	6,564			3,986,251	19,945,981	3.28	
6	*Desoto Solar*												
7	Solar		3,596					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,596	20.0%		20.0%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	383	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,179					3,675	5,830,476	21,427	442,783	37.56	120.49
15	Plant Unit Info	690	1,179	0.2%	93.5%	34.2%	18,174			21,427	442,783	37.56	
16	*Fort Myers 2*												
17	Gas		267,875					1,966,298	1,000,000	1,966,298	9,961,028	3.72	5.07
18	Plant Unit Info	1,440	267,875	25.8%	61.5%	66.2%	7,340			1,966,298	9,961,028	3.72	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		5,550					59,908	1,000,000	59,908	305,757	5.51	5.10
22	Plant Unit Info	314	5,550	4.9%	95.1%	98.1%	10,794			59,908	305,757	5.51	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	766	0	0.0%	93.5%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		25,065					203,908	1,000,000	203,908	1,040,771	4.15	5.10
30	Plant Unit Info	447	25,065	7.8%	94.6%	90.4%	8,135			203,908	1,040,771	4.15	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		0					0	0	0	0	0.00	0.00
34	Plant Unit Info	447	0	0.0%	3.1%	0.0%	0			0	0	0.00	
35	*Manatee 1*												
36	Heavy Oil		11,355					19,512	6,399,856	124,874	1,753,445	15.44	89.86
37	Gas		10,022					104,607	1,000,000	104,607	532,959	5.32	5.09

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	798	21,377	3.7%	96.9%	57.0%	10,735			229,481	2,286,404	10.70	
2	*Manatee 2*												
3	Heavy Oil		7,855					13,877	6,400,014	88,813	1,369,709	17.44	98.70
4	Gas		5,237					53,769	1,000,000	53,769	274,466	5.24	5.10
5	Plant Unit Info	798	13,092	2.3%	95.0%	68.4%	10,891			142,582	1,644,176	12.56	
6	*Manatee 3*												
7	Gas		582,589					3,987,761	1,000,000	3,987,761	20,252,373	3.48	5.08
8	Plant Unit Info	1,117	582,589	72.4%	94.9%	91.7%	6,845			3,987,761	20,252,373	3.48	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		2,694					3,948	6,400,709	25,270	362,758	13.47	91.88
15	Gas		6,286					69,911	1,000,000	69,911	356,690	5.67	5.10
16	Plant Unit Info	808	8,980	1.5%	95.0%	69.5%	10,600			95,181	719,448	8.01	
17	*Martin 3*												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	462	0	0.0%	0.0%	0.0%	0			0	0	0.00	
20	*Martin 4*												
21	Gas		52,716					388,223	1,000,000	388,223	1,965,496	3.73	5.06
22	Plant Unit Info	462	52,716	15.9%	94.8%	93.5%	7,364			388,223	1,965,496	3.73	
23	*Martin 8*												
24	Gas		612,749					4,227,860	1,000,000	4,227,860	21,430,087	3.50	5.07
25	Plant Unit Info	1,112	612,749	76.5%	89.4%	87.5%	6,900			4,227,860	21,430,087	3.50	
26	*Martin 8 Solar*												
27	Solar		4,308					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	4,308	8.0%		8.0%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		9,434					84,673	1,000,000	84,673	432,085	4.58	5.10
32	Plant Unit Info	248	9,434	5.3%	87.1%	86.5%	8,975			84,673	432,085	4.58	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		3,914					43,235	1,000,000	43,235	220,468	5.63	5.10
36	Plant Unit Info	248	3,914	2.2%	63.0%	43.8%	11,046			43,235	220,468	5.63	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		299,389					2,144,434	1,000,000	2,144,434	10,862,812	3.63	5.07
2	Plant Unit Info	955	299,389	43.5%	95.8%	93.0%	7,163			2,144,434	10,862,812	3.63	
3	*Sanford 5*												
4	Gas		207,493					1,496,219	1,000,000	1,496,219	7,580,878	3.65	5.07
5	Plant Unit Info	952	207,493	30.3%	94.8%	92.4%	7,211			1,496,219	7,580,878	3.65	
6	*Scherer 4*												
7	Coal		345,398					206,972	16,999,976	3,518,519	8,132,400	2.35	39.29
8	Plant Unit Info	635	345,398	75.6%	93.8%	86.2%	10,187			3,518,519	8,132,400	2.35	
9	*St Johns 1Q*												
10	Coal		40,067					19,469	21,999,743	428,313	1,503,600	3.75	77.23
11	Plant Unit Info	124	40,067	44.9%	94.1%	44.9%	10,690			428,313	1,503,600	3.75	
12	*St Johns 2Q*												
13	Coal		44,360					21,064	22,000,190	463,412	1,626,900	3.67	77.24
14	Plant Unit Info	124	44,360	49.7%	94.0%	49.7%	10,447			463,412	1,626,900	3.67	
15	*St Lucie 1*												
16	Nuclear		633,695					6,544,958	1,000,000	6,544,958	4,574,000	0.72	0.70
17	Plant Unit Info	1,003	633,695	87.8%	87.8%	97.5%	10,328			6,544,958	4,574,000	0.72	
18	*St Lucie 2*												
19	Nuclear		603,721					6,173,813	1,000,000	6,173,813	4,428,300	0.73	0.72
20	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,226			6,173,813	4,428,300	0.73	
21	*Space Coast*												
22	Solar		1,228					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,228	17.1%		17.1%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	380	0	0.0%	12.6%	0.0%	0			0	0	0.00	
28	*Turkey Point 3*												
29	Nuclear		584,765					6,356,602	1,000,000	6,356,602	4,961,100	0.85	0.78
30	Plant Unit Info	833	584,765	97.5%	97.8%	97.5%	10,870			6,356,602	4,961,100	0.85	
31	*Turkey Point 4*												
32	Nuclear		591,786					6,432,893	1,000,000	6,432,893	4,490,500	0.76	0.70
33	Plant Unit Info	843	591,786	97.5%	98.0%	97.5%	10,870			6,432,893	4,490,500	0.76	
34	*Turkey Point 5*												
35	Gas		443,948					3,092,876	1,000,000	3,092,876	15,765,692	3.55	5.10
36	Plant Unit Info	1,114	443,948	55.4%	94.9%	91.0%	6,967			3,092,876	15,765,692	3.55	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		767,985					5,226,203	1,000,000	5,226,203	26,553,987	3.46	5.08
2	Plant Unit Info	1,335	767,985	79.9%	94.7%	80.9%	6,805			5,226,203	26,553,987	3.46	
3	*WCEC 02*												
4	Gas		806,986					5,498,434	1,000,000	5,498,434	27,731,060	3.44	5.04
5	Plant Unit Info	1,335	806,986	84.0%	94.7%	84.0%	6,814			5,498,434	27,731,060	3.44	
6	*WCEC 03*												
7	Gas		456,122					3,126,553	1,000,000	3,126,553	15,664,386	3.43	5.01
8	Plant Unit Info	1,335	456,122	47.5%	70.3%	72.8%	6,855			3,126,553	15,664,386	3.43	
9	**System Totals**												
10	Plant Unit Info	24,641	8,046,691				8,195			65,940,015	214,522,470	2.67	
11													
12													
13													
14													
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16													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Dec - 2013**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		796,375					5,231,007	1,000,000	5,231,007	26,568,402	3.34	5.08
5	Plant Unit Info	1,355	796,375	79.0%	94.7%	79.0%	6,569			5,231,007	26,568,402	3.34	
6	*Desoto Solar*												
7	Solar		3,265					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,265	17.6%		17.6%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	383	0	0.0%	93.5%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	93.5%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		360,324					2,568,647	1,000,000	2,568,647	13,217,974	3.67	5.15
18	Plant Unit Info	1,440	360,324	33.6%	94.2%	90.3%	7,129			2,568,647	13,217,974	3.67	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		1,233					13,357	1,000,000	13,357	69,158	5.61	5.18
22	Plant Unit Info	314	1,233	1.1%	95.1%	98.1%	10,831			13,357	69,158	5.61	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	766	0	0.0%	93.5%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		28,005					225,452	1,000,000	225,452	1,167,714	4.17	5.18
30	Plant Unit Info	447	28,005	8.4%	94.6%	81.4%	8,050			225,452	1,167,714	4.17	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		15,899					128,809	1,000,000	128,809	667,069	4.20	5.18
34	Plant Unit Info	447	15,899	4.8%	82.0%	86.8%	8,102			128,809	667,069	4.20	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	798	0	0.0%	96.9%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	798	0	0.0%	95.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		460,112					3,170,581	1,000,000	3,170,581	16,362,188	3.56	5.16
8	Plant Unit Info	1,117	460,112	55.4%	94.9%	91.3%	6,891			3,170,581	16,362,188	3.56	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	808	0	0.0%	64.3%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		0					0	0	0	0	0.00	0.00
19	Plant Unit Info	462	0	0.0%	39.5%	0.0%	0			0	0	0.00	
20	*Martin 4*												
21	Gas		56,820					416,947	1,000,000	416,947	2,143,930	3.77	5.14
22	Plant Unit Info	462	56,820	16.5%	94.8%	91.8%	7,338			416,947	2,143,930	3.77	
23	*Martin 8*												
24	Gas		607,254					4,175,367	1,000,000	4,175,367	21,496,419	3.54	5.15
25	Plant Unit Info	1,112	607,254	73.4%	94.9%	90.9%	6,876			4,175,367	21,496,419	3.54	
26	*Martin 8 Solar*												
27	Solar		3,564					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	3,564	6.4%		6.4%	0			0	0	0.00	
29	*Putnam 1*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		8,989					83,717	1,000,000	83,717	433,185	4.82	5.17
32	Plant Unit Info	248	8,989	4.9%	95.0%	72.5%	9,313			83,717	433,185	4.82	
33	*Putnam 2*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		4,563					42,418	1,000,000	42,418	219,389	4.81	5.17
36	Plant Unit Info	248	4,563	2.5%	94.4%	73.6%	9,296			42,418	219,389	4.81	
37	*Sanford 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		263,918					1,883,556	1,000,000	1,883,556	9,688,024	3.67	5.14
2	Plant Unit Info	955	263,918	37.1%	95.8%	92.7%	7,137			1,883,556	9,688,024	3.67	
3	*Sanford 5*												
4	Gas		138,301					993,726	1,000,000	993,726	5,112,131	3.70	5.14
5	Plant Unit Info	952	138,301	19.5%	94.8%	92.5%	7,185			993,726	5,112,131	3.70	
6	*Scherer 4*												
7	Coal		311,998					186,484	17,000,005	3,170,229	7,333,100	2.35	39.32
8	Plant Unit Info	635	311,998	66.0%	93.8%	93.1%	10,161			3,170,229	7,333,100	2.35	
9	*St Johns 1O*												
10	Coal		38,629					19,032	22,000,420	418,712	1,468,800	3.80	77.18
11	Plant Unit Info	124	38,629	41.9%	94.1%	41.9%	10,839			418,712	1,468,800	3.80	
12	*St Johns 2O*												
13	Coal		41,701					20,173	21,999,752	443,801	1,556,800	3.73	77.17
14	Plant Unit Info	124	41,701	45.2%	94.0%	45.2%	10,642			443,801	1,556,800	3.73	
15	*St Lucie 1*												
16	Nuclear		727,574					7,514,567	1,000,000	7,514,567	5,251,600	0.72	0.70
17	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	5,251,600	0.72	
18	*St Lucie 2*												
19	Nuclear		623,845					6,379,606	1,000,000	6,379,606	4,575,900	0.73	0.72
20	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,226			6,379,606	4,575,900	0.73	
21	*Space Coast*												
22	Solar		1,086					0	0	0	0	0.00	0.00
23	Plant Unit Info	10	1,086	14.6%		14.6%	0			0	0	0.00	
24	*Turkey Point 1*												
25	Heavy Oil		0					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	380	0	0.0%	94.5%	0.0%	0			0	0	0.00	
28	*Turkey Point 3*												
29	Nuclear		604,258					6,568,489	1,000,000	6,568,489	5,126,500	0.85	0.78
30	Plant Unit Info	833	604,258	97.5%	97.8%	97.5%	10,870			6,568,489	5,126,500	0.85	
31	*Turkey Point 4*												
32	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,640,200	0.76	0.70
33	Plant Unit Info	843	611,511	97.5%	98.0%	97.5%	10,870			6,647,323	4,640,200	0.76	
34	*Turkey Point 5*												
35	Gas		385,253					2,684,060	1,000,000	2,684,060	13,869,342	3.60	5.17
36	Plant Unit Info	1,114	385,253	46.5%	94.9%	88.4%	6,967			2,684,060	13,869,342	3.60	
37	*WCEC 01*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Gas		737,587					5,012,518	1,000,000	5,012,518	25,851,948	3.50	5.16
2	Plant Unit Info	1,335	737,587	74.3%	94.7%	78.7%	6,796			5,012,518	25,851,948	3.50	
3	*WCEC 02*												
4	Gas		805,267					5,476,523	1,000,000	5,476,523	28,214,436	3.50	5.15
5	Plant Unit Info	1,335	805,267	81.1%	94.7%	81.1%	6,801			5,476,523	28,214,436	3.50	
6	*WCEC 03*												
7	Gas		728,835					4,878,879	1,000,000	4,878,879	24,828,187	3.41	5.09
8	Plant Unit Info	1,335	728,835	73.4%	90.4%	88.6%	6,694			4,878,879	24,828,187	3.41	
9	**System Totals**												
10	Plant Unit Info	24,641	8,366,167				8,143			68,128,290	219,862,398	2.63	
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) Jul - 2013	(3) Aug - 2013	(4) Sep - 2013	(5) Oct - 2013	(6) Nov - 2013	(7) Dec - 2013	(8) Jul:Dec - 2013
1	**#6 Heavy Oil (BBLS)**							
2	Purchases							
3	Units	0	255,000	145,000	0	0	0	400,000
4	Unit Cost	0.0000	97.3768	96.0864	0.0000	0.0000	0.0000	96.9090
5	Amount	$0	$24,831,082	$13,932,528	$0	$0	$0	$38,763,610
6	Burned							
7	Units	116,455	157,007	275,152	83,186	37,337	0	669,137
8	Unit Cost	92.8088	93.3017	93.4663	93.0830	93.3635	0.0000	93.2599
9	Amount	$10,808,051	$14,649,027	$25,717,445	$7,743,199	$3,485,913	$0	$62,403,634
10	Ending Inventory							
11	Units	2,801,231	2,899,224	2,769,072	2,685,886	2,648,549	2,648,549	2,648,549
12	Unit Cost	92.6609	93.0410	93.1582	93.1605	93.1577	93.1577	93.1577
13	Amount	$259,564,639	$269,746,694	$257,961,776	$250,218,578	$246,732,665	$246,732,665	$246,732,665
14	**#2 Light Oil (BBLS)**							
15	Purchases							
16	Units	60,848	13,905	19,950	0	150,000	0	244,703
17	Unit Cost	128.5550	132.3334	132.5602	0.0000	132.0769	0.0000	131.2551
18	Amount	$7,822,313	$1,840,096	$2,644,576	$0	$19,811,535	$0	$32,118,521
19	Burned							
20	Units	11,052	10,180	13,938	1,433	3,675	0	40,278
21	Unit Cost	119.3485	119.8378	120.4851	120.4851	120.4851	0.0000	120.0096
22	Amount	$1,319,040	$1,219,949	$1,679,321	$172,655	$442,783	$0	$4,833,747
23	Ending Inventory							
24	Units	1,300,500	1,300,500	1,300,500	1,299,067	1,445,392	1,445,392	1,445,392
25	Unit Cost	115.5428	115.6407	115.7701	115.7649	117.4457	117.4457	117.4457
26	Amount	$150,263,473	$150,390,678	$150,558,981	$150,386,326	$169,755,079	$169,755,079	$169,755,079
27	**Coal - SJRPP (TONS)**							
28	Purchases							
29	Units	60,168	57,218	56,473	50,829	40,532	39,204	304,424
30	Unit Cost	76.9346	76.9863	76.9040	77.2394	77.2229	77.1860	77.0603
31	Amount	$4,629,000	$4,405,000	$4,343,000	$3,926,000	$3,130,000	$3,026,000	$23,459,000
32	Burned							
33	Units	60,168	57,218	56,473	50,829	40,532	39,204	304,424
34	Unit Cost	76.9346	76.9863	76.9040	77.2394	77.2229	77.1860	77.0603
35	Amount	$4,629,000	$4,405,000	$4,343,000	$3,926,000	$3,130,000	$3,026,000	$23,459,000
36	Ending Inventory							
37	Units	91,000	91,000	91,000	91,000	91,000	90,999	90,999
38	Unit Cost	76.6593	76.6593	76.6593	76.6593	76.6593	76.6602	76.6602
39	Amount	$6,976,000	$6,976,000	$6,976,000	$6,976,000	$6,976,000	$6,976,000	$6,976,000
40								

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) Jul - 2013	(3) Aug - 2013	(4) Sep - 2013	(5) Oct - 2013	(6) Nov - 2013	(7) Dec - 2013	(8) Jul:Dec - 2013
1	**Coal - Scherer (MMBTU)**							
2	Purchases							
3	Units	3,855,906	3,560,089	3,742,839	3,488,298	3,518,524	3,170,228	21,335,884
4	Unit Cost	2.3001	2.3084	2.3073	2.3057	2.3112	2.3131	2.3074
5	Amount	$8,869,000	$8,218,000	$8,636,000	$8,043,000	$8,132,000	$7,333,000	$49,231,000
6	Burned							
7	Units	3,855,906	3,560,089	3,742,839	3,488,298	3,518,524	3,170,228	21,335,884
8	Unit Cost	2.3001	2.3084	2.3073	2.3057	2.3112	2.3131	2.3074
9	Amount	$8,869,000	$8,218,000	$8,636,000	$8,043,000	$8,132,000	$7,333,000	$49,231,000
10	Ending Inventory							
11	Units	5,035,417	5,035,417	5,035,417	5,035,417	5,035,418	5,035,417	5,035,417
12	Unit Cost	2.3066	2.3066	2.3066	2.3066	2.3066	2.3066	2.3066
13	Amount	$11,614,941	$11,614,941	$11,614,941	$11,614,941	$11,614,941	$11,614,941	$11,614,941
14	**Gas (MCF)**							
15	Burned							
16	Units	52,395,885	53,075,883	47,023,895	48,591,932	35,761,121	36,985,563	273,834,279
17	Unit Cost	4.8424	4.7695	4.8368	4.8004	5.0579	5.1347	4.8875
18	Amount	$253,719,552	$253,145,418	$227,446,256	$233,259,354	$180,876,975	$189,909,498	$1,338,357,053
19	**Nuclear (Other)**							
20	Burned							
21	Units	27,094,244	27,094,244	25,977,833	19,579,677	25,508,266	27,109,985	152,364,249
22	Unit Cost	0.7228	0.7228	0.7230	0.7319	0.7235	0.7228	0.7241
23	Amount	$19,583,000	$19,583,000	$18,781,000	$14,331,000	$18,454,000	$19,594,000	$110,326,000
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FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	SOLD TO	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total $ for Fuel Adjustment (Col(4) * Col(5))	Total Cost ($) (Col(4) * Col(6))	Gain from Off System Sales ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1									
2	**July Estimated**								
3	Off System	OS	65,000	65,000	5.932	6.971	$3,855,900	$4,530,900	$516,250
4	St Lucie Reliability Sales		52,999	52,999	0.738	0.738	$391,207	$391,207	$0
5	**Total July Estimated**		117,999	117,999	3.599	4.171	$4,247,107	$4,922,107	$516,250
6									
7	**August Estimated**								
8	Off System	OS	75,000	75,000	5.914	6.934	$4,435,500	$5,200,500	$588,750
9	St Lucie Reliability Sales		52,999	52,999	0.738	0.738	$391,207	$391,207	$0
10	**Total August Estimated**		127,999	127,999	3.771	4.369	$4,826,707	$5,591,707	$588,750
11									
12	**September Estimated**								
13	Off System	OS	35,000	35,000	7.435	8.478	$2,602,150	$2,967,150	$278,750
14	St Lucie Reliability Sales		49,580	49,580	0.738	0.738	$365,968	$365,968	$0
15	**Total September Estimated**		84,580	84,580	3.509	3.941	$2,968,118	$3,333,118	$278,750
16									
17	**October Estimated**								
18	Off System	OS	40,000	40,000	4.480	5.493	$1,792,000	$2,197,000	$312,500
19	St Lucie Reliability Sales		0	0	0.000	0.000	$0	$0	$0
20	**Total October Estimated**		40,000	40,000	4.480	5.492	$1,792,000	$2,197,000	$312,500
21									
22	**November Estimated**								
23	Off System	OS	100,000	100,000	3.401	4.301	$3,400,500	$4,300,500	$675,000
24	St Lucie Reliability Sales		47,197	47,197	0.722	0.722	$340,729	$340,729	$0
25	**Total November Estimated**		147,197	147,197	2.542	3.153	$3,741,229	$4,641,229	$675,000
26									
27	**December Estimated**								
28	Off System	OS	190,000	190,000	2.762	3.656	$5,247,200	$6,947,200	$1,277,500
29	St Lucie Reliability Sales		54,189	54,189	0.722	0.722	$391,207	$391,207	$0
30	**Total December Estimated**		244,189	244,189	2.309	3.005	$5,638,407	$7,338,407	$1,277,500
31									
32	**Period Total**								
33	Off System	OS	505,000	505,000	4.224	5.177	$21,333,250	$26,143,250	$3,648,750
34	St Lucie Reliability Sales		256,964	256,964	0.732	0.732	$1,880,319	$1,880,319	$0
35	**Total Period Total**		761,964	761,964	3.047	3.678	$23,213,569	$28,023,569	$3,648,750
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	July Estimated					
3	UPS		253,643	253,643	3.725	$9,448,739
4	SJRPP		206,596	206,596	3.537	$7,308,000
5	St Lucie Reliability		45,379	45,379	0.754	$342,181
6	**Total July Estimated**		505,618	505,618	3.382	$17,098,920
7						
8	August Estimated					
9	UPS		238,070	238,070	3.685	$8,771,832
10	SJRPP		198,991	198,991	3.556	$7,076,000
11	St Lucie Reliability		45,379	45,379	0.754	$342,181
12	**Total August Estimated**		482,440	482,440	3.356	$16,190,014
13						
14	September Estimated					
15	UPS		270,887	270,887	3.660	$9,914,998
16	SJRPP		195,418	195,418	3.547	$6,932,000
17	St Lucie Reliability		43,920	43,920	0.754	$331,162
18	**Total September Estimated**		510,225	510,225	3.367	$17,178,160
19						
20	October Estimated					
21	UPS		216,942	216,942	3.691	$8,007,054
22	SJRPP		174,397	174,397	3.621	$6,315,000
23	St Lucie Reliability		45,379	45,379	0.306	$139,050
24	**Total October Estimated**		436,718	436,718	3.311	$14,461,104
25						
26	November Estimated					
27	UPS		93,686	93,686	3.900	$3,653,925
28	SJRPP		136,866	136,866	3.684	$5,042,000
29	St Lucie Reliability		44,965	44,965	0.738	$331,628
30	**Total November Estimated**		275,517	275,517	3.277	$9,027,553
31						
32	December Estimated					
33	UPS		82,813	82,813	3.976	$3,292,376
34	SJRPP		128,257	128,257	3.749	$4,808,000
35	St Lucie Reliability		46,464	46,464	0.738	$342,682
36	**Total December Estimated**		257,534	257,534	3.278	$8,443,059
37						
38	Period Total					
39	UPS		1,156,041	1,156,041	3.727	$43,088,923
40	SJRPP		1,040,525	1,040,525	3.602	$37,481,000
41	St Lucie Reliability		271,487	271,487	0.674	$1,828,885
42	**Total Period Total**		2,468,053	2,468,053	3.339	$82,398,809
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JULY 2013 THROUGH DECEMBER 2013

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) Transaction Cost (cents/KWH)	(5) Total $ for Fuel Adj (Col(3) * Col(4))	(6) Cost if Generated (cents/KWH)	(7) Cost if Generated ($) (Col(3) * Col(6))	(8) Fuel Savings ($) (Col(7) - Col(5))
1								
2	**July Estimated**							
3	Economy	OS	5,000	5.000	$250,000	7.210	$360,500	$110,500
4	Total July Estimated		5,000	5.000	$250,000	7.210	$360,500	$110,500
5								
6	**August Estimated**							
7	Economy	OS	10,000	5.000	$500,000	7.784	$778,400	$278,400
8	Total August Estimated		10,000	5.000	$500,000	7.784	$778,400	$278,400
9								
10	**September Estimated**							
11	Economy	OS	30,000	4.500	$1,350,000	9.237	$2,771,100	$1,421,100
12	Total September Estimated		30,000	4.500	$1,350,000	9.237	$2,771,100	$1,421,100
13								
14	**October Estimated**							
15	Economy	OS	35,000	3.500	$1,225,000	5.838	$2,043,300	$818,300
16	Total October Estimated		35,000	3.500	$1,225,000	5.838	$2,043,300	$818,300
17								
18	**November Estimated**							
19	Economy	OS	2,000	2.800	$56,000	4.121	$82,420	$26,420
20	Total November Estimated		2,000	2.800	$56,000	4.121	$82,420	$26,420
21								
22	**December Estimated**							
23	Economy	OS	2,000	2.200	$44,000	3.008	$60,160	$16,160
24	Total December Estimated		2,000	2.200	$44,000	3.008	$60,160	$16,160
25								
26	**Period Total**							
27	Economy	OS	84,000	4.077	$3,425,000	7.257	$6,095,880	$2,670,880
28	Total Period Total		84,000	4.077	$3,425,000	7.257	$6,095,880	$2,670,880
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APPENDIX II

CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP CALCULATION

TJK-4
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
August 2, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI **EXHIBIT** 13
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-4

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) Total
1	Payments to Non-cogenerators	$16,437,513	$16,618,240	$17,107,824	$16,482,672	$16,487,283	$16,076,979	$16,301,176	$16,214,757	$17,059,834	$16,492,116	$16,259,876	$16,286,036	$197,824,305
2	Payments to Co-generators	$25,038,297	$25,205,917	$20,512,305	$23,359,041	$22,728,373	$23,148,194	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$278,518,255
3	SJRPP Suspension Accrual	$0	$0	($2,582,946)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return on SJRPP Suspension Liability	($445,444)	($445,444)	($435,246)	($421,647)	($414,848)	($408,049)	($405,660)	($398,786)	($391,912)	($385,038)	($378,164)	($371,291)	($4,901,530)
5	Incremental Plant Security PSC Order No. 02-1761	$2,742,107	$3,070,332	$3,468,119	$3,248,334	$2,732,257	$3,485,081	$3,239,994	$5,208,263	$5,387,066	$4,104,789	$4,317,518	$6,176,809	$47,180,669
6	Incremental Nuclear NRC Compliance Costs O&M	$25,179	$174,820	($37,256)	($3,346)	$23,650	($83,471)	$2,404	($3,127)	$46,873	($3,127)	($3,127)	($56,471)	$83,000
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,587	$17,587
8	Transmission of Electricity by Others	$2,270,836	$2,203,512	$2,161,119	$1,343,872	$1,441,836	($627,741)	$1,488,962	$1,541,868	$1,399,703	$1,613,647	$2,021,776	$2,069,324	$18,928,713
9	Transmission Revenues from Capacity Sales	($329,135)	($578,809)	($845,612)	($380,813)	($477,335)	($249,378)	($158,750)	($176,250)	($86,250)	($92,500)	($225,000)	($422,500)	($4,022,332)
10	Total (Lines 1 through 9)	$45,739,352	$46,248,567	$39,348,308	$42,767,130	$41,660,233	$40,480,632	$42,694,832	$44,613,432	$45,642,019	$43,956,593	$44,219,584	$45,926,201	$523,296,883
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	N/A
12	Jurisdictional CCR	$44,810,990	$45,309,869	$38,549,663	$41,899,094	$40,814,664	$39,659,005	$41,828,264	$43,707,922	$44,715,632	$43,064,414	$43,322,068	$44,994,046	$512,675,631
13	Nuclear Cost Recovery Costs	$12,249,674	$14,229,199	$14,667,616	$13,013,524	$12,802,720	$12,659,892	$12,277,795	$12,200,448	$12,000,152	$11,888,604	$11,726,916	$11,774,862	$151,491,402
14	Jurisdictional CCR	$57,060,664	$59,539,068	$53,217,280	$54,912,618	$53,617,383	$52,318,897	$54,106,058	$55,908,370	$56,715,784	$54,953,018	$55,048,985	$56,768,908	$664,167,034
15	CCR Revenues (Net of Revenue Taxes)	$52,434,454	$49,413,054	$49,832,052	$53,331,531	$58,351,845	$61,903,701	$68,768,050	$68,299,950	$66,148,216	$61,684,870	$55,930,151	$54,654,912	700,752,785
16	Prior Period True-up Provision	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($60,583,035)
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$47,385,867	$44,364,468	$44,783,466	$48,282,945	$53,303,259	$56,855,115	$63,719,463	$63,251,364	$61,099,629	$56,636,284	$50,881,565	$49,606,325	$640,169,750
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($9,674,797)	($15,174,600)	($8,433,814)	($6,629,673)	($314,124)	$4,536,218	$9,613,405	$7,342,994	$4,383,845	$1,683,266	($4,167,420)	($7,162,583)	($23,997,284)
19	Interest Provision for Month	($4,128)	($6,193)	($6,371)	($5,832)	($5,367)	($4,266)	($3,330)	($2,654)	($2,108)	($1,704)	($1,514)	($1,545)	($45,013)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($65,213,374)	($75,345,580)	($78,737,179)	($80,324,099)	($75,595,003)	($66,014,466)	($51,355,804)	($38,966,878)	($29,536,555)	($22,806,407)	($21,926,755)	($60,583,035)
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$60,583,035
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($73,126,858)	($83,259,064)	($86,650,663)	($88,237,583)	($83,508,487)	($73,927,950)	($59,269,288)	($46,880,362)	($37,450,039)	($30,719,891)	($29,840,239)	($31,955,780)	($31,955,780)
24														
25	[a] As approved on Order No PSC-12-0664-FOF-EI													
26														
27	Totals may not add up due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCES
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1) CCR - Actual Estimated Variance	(2) CCR - 2013 Actual/Estimated	(3) CCR - 2013 Original Projection	(4) Dif. CCR - 2013 Original Projection	(5) % Dif. CCR - 2013 Original Projection
1	Payments to Non-cogenerators	$197,824,305	$199,776,283	($1,951,978)	(1.0%)
2	Payments to Co-generators	$278,518,255	$270,601,412	$7,916,842	2.9%
3	SJRPP Suspension Accrual	($10,331,784)	$935,844	($11,267,628)	(1,204.0%)
4	Return on SJRPP Suspension Liability	($4,901,530)	($5,304,459)	$402,929	(7.6%)
5	Incremental Plant Security PSC Order No. 02-1761	$47,180,669	$46,396,506	$784,163	1.7%
6	Incremental Nuclear NRC Compliance Costs O&M	$83,000	$0	$83,000	N/A
7	Incremental Nuclear NRC Compliance Costs Capital	$17,587	$0	$17,587	N/A
8	Transmission of Electricity by Others	$18,928,713	$18,402,144	$526,569	2.9%
9	Transmission Revenues from Capacity Sales	($4,022,332)	($1,209,884)	($2,812,448)	232.5%
10	Total (Lines 1 through 9)	$523,296,883	$529,597,847	($6,300,963)	(1.2%)
11	Jurisdictional Separation Factor [a]	97.97032%	97.97032%	0.00000%	0.0%
12	Jurisdictional CCR	$512,675,631	$518,848,705	($6,173,074)	(1.2%)
13	Nuclear Cost Recovery Costs	$151,491,402	$151,491,402	$0	0.0%
14	Jurisdictional CCR	$664,167,034	$670,340,107	($6,173,074)	(0.9%)
15	CCR Revenues (Net of Revenue Taxes)	$700,752,785	$730,923,142	($30,170,357)	(4.1%)
16	Prior Period True-up Provision	($60,583,035)	($60,583,035)	$0	0.0%
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$640,169,750	$670,340,107	($30,170,357)	(4.5%)
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($23,997,284)	$0	($23,997,284)	0.0%
19	Interest Provision for Month	($45,013)	$0	($45,013)	N/A
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($60,583,035)	$0	0.0%
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	$0	($7,913,484)	N/A
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$60,583,035	$60,583,035	$0	0.0%
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($31,955,780)	$0	($31,955,780)	0.0%
24					
25	[a] As approved in order no PSC-12-0664-FOF-EI				
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

ESTIMATED FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$6,814,592	$1,955,779	$2,416,515	$2,031,919	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base [a]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,814,592	$8,770,372	$11,186,886	$13,218,806	N/A
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,814,592	$8,770,372	$11,186,886	$13,218,806	N/A
6. Total Estimated Capital Expenditures Included in Base Rates [b]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
7. Base Rate Capital Expenditures Closed to Plant-in-Service [c]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
9. Adjusted Net Investment (Lines 5 - 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,185,408)	($1,229,628)	$1,186,886	$3,218,806	N/A
10. Average Net Investment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,202,846	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,713	$14,713
b. Debt Component (Line 10 x debt rate x 1/12) [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,874	$2,874
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,587	$17,587

[a] Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

[b] Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

[c] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

[d] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2013 actual period is 4.8339% based on rate case Order No. PSC-13-0023-S-EI and reflects a 10.5% return on equity, and the monthly Equity Component for the Jul. – Dec. 2013 estimated period is 4.9230% based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

APPENDIX II
FUEL COST RECOVERY
2014 E-SCHEDULES

FOR THE PERIOD JANUARY 2014 THROUGH MAY 2014

TJK-5
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-77
AUGUST 30, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 14
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-5

APPENDIX II
FUEL COST RECOVERY
2014 E SCHEDULES
TABLE OF CONTENTS

PAGE(S)	SCHEDULES	SPONSOR
1	Schedule E1 Fuel & Purchased Power Cost Recovery Clause Calculation	T.J. Keith
2	Schedule E1-A Calculation of Total True-Up (Projected Period)	T.J. Keith
3	Schedule E1-B Revised Actual/Estimated True-Up Calculation	T.J. Keith
4	Schedule E1-C Calculation Generating Performance Incentive Factor and True-up Factor	T.J. Keith
5-6	Schedule E1-D Time of Use Rate Schedule	T.J. Keith
7-8	Schedule E1-E Factors by Rate Group	T.J. Keith
9-11	2014 Projected Energy Losses by Rate Class	T.J. Keith
12	Schedule E2 Monthly Summary of Fuel & Purchased Power Cost Recovery Clause Calculation	T.J. Keith / G. Yupp
13	Inverted Rate Calculation – RS-1	T.J. Keith
14-15	Schedule E3 Monthly Summary of Generating System Data	G. Yupp / D. Grissette
16-63	Schedule E4 Monthly Generation and Fuel Cost by Unit	G. Yupp / D. Grissette
64-65	Schedule E5 Monthly Fuel Inventory Data	G. Yupp / D. Grissette
66-67	Schedule E6 Monthly Power Sold Data	G. Yupp / D. Grissette
68-69	Schedule E7 Monthly Purchased Power Data	G. Yupp
70-71	Schedule E8 Energy Payment to Qualifying Facilities	G. Yupp
72-73	Schedule E9 Monthly Economy Energy Purchase Data	G. Yupp
74	Schedule E10 Residential Bill Comparison	T.J. Keith
75	Schedule H1 Three Year Historical Comparison	T.J. Keith
76-77	Cogeneration Tariff Sheets	T.J. Keith

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,248,141,556	112,677,379	2.8827
2	Riviera Beach Energy Center (RBEC) Savings	$82,000,000	112,677,379	0.0728
3	Nuclear Fuel Disposal Costs (E2)	$26,064,319	27,766,399	0.0939
4	TOTAL COST OF GENERATED POWER	$3,356,205,875	112,677,379	2.9786
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$144,323,495	4,102,190	3.5182
6	Energy Cost of Economy Purchases (E9)	$13,403,538	278,500	4.8128
7	Payments to Qualifying Facilities (E8)	$126,567,361	2,940,405	4.3044
8	TOTAL COST OF PURCHASED POWER	$284,294,395	7,321,095	3.8832
9	TOTAL AVAILABLE MWH (LINE 4 + LINE 8)		119,998,473	
10	Fuel Cost of Economy Sales (E6)	($65,345,750)	(1,655,000)	3.9484
11	Gain from Off-System Sales (E6)	($11,080,000)	N/A	N/A
12	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,342,565)	(629,817)	0.6895
13	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,768,315)	(2,284,817)	3.5350
14	Incremental Personnel, Software, and Hardware Costs	$389,472	N/A	N/A
15	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,722,910	N/A	N/A
16	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,112,382	N/A	N/A
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 4 + 8 + 13 + 16)	$3,561,844,337	117,713,657	3.0259
18	Net Unbilled Sales [1]	($32,030,707)	(1,058,567)	(0.0289)
19	Company Use [1]	$10,685,533	353,141	0.0096
20	T & D Losses [1]	$231,519,882	7,651,388	0.2090
21	SYSTEM MWH SALES	$3,561,844,337	110,767,695	3.2156
22	Wholesale MWH Sales	$158,351,051	4,924,470	3.2156
23	Jurisdictional MWH Sales	$3,403,493,286	105,843,225	3.2156
24	Jurisdictional Loss Multiplier	$5,751,904		1.00169
25	Jurisdictional MWH Sales Adjusted for Line Losses	$3,409,245,189	105,843,225	3.2210
26	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$147,765,613	105,843,225	0.1396
27	TOTAL JURISDICTIONAL FUEL COST	$3,557,010,803	105,843,225	3.3606
28	Revenue Tax Factor	$2,561,048		1.00072
29	Fuel Factor Adjusted for Taxes	$3,559,571,851	105,843,225	3.3630
30	GPIF [2]	$20,679,970	105,843,225	0.0195
31	Fuel Factor including GPIF (Line 29 + Line 30)	$3,580,251,821	105,843,225	3.3825
32	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.383
33				
34	[1] For Informational Purposes Only			
35	[2] Calculation Based on Jurisdictional KWH Sales			
36				
37	Note: Totals may not add due to rounding.			
38				

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)

SCHEDULE: E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery [1]	($143,214,959)
2	Final over/(under) recovery [2]	($4,550,654)
3	Total over/(under) recovery to be included in projected period [3]	($147,765,613)
4		
5	Total Jurisdictional Sales (MWH)	105,843,225
6		
7	True-Up Factor (cents/kWh)	(0.1396)
8		
9	[1] Actual/Estimated over/(under) recovery for January 2013 - December 2013	
10	[2] Final over/(under) recovery for January 2012 - December 2012	
11	[3] Projected Period January 2014 - December 2014 (Schedule E1, Line 26)	
12		
13	Note: Totals may not add due to rounding.	
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

REVISED - SCHEDULE: E1-B

FOR THE PERIOD OF: JANUARY 2013 THROUGH DECEMBER 2013

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) [1]	$220,037,900	$208,050,632	$234,633,600	$267,219,326	$276,720,275	$286,666,776	$280,951,961	$301,405,743	$286,677,773	$267,474,908	$214,522,470	$219,862,398	$3,064,223,762
3	Nuclear Fuel Disposal Costs (Per A2)	$1,880,395	$1,417,734	$1,144,529	$1,819,397	$2,007,177	$2,256,251	$2,453,484	$2,341,856	$2,244,819	$1,675,564	$2,260,197	$2,403,658	$23,905,061
4	Scherer Coal Cars Depreciation & Return	$0	($181)	($46,136)	($207)	($416)	($416)	($53,299)	$0	$0	$0	$0	$0	($100,655)
5	Fuel Cost of Power Sold (Per A6)	($3,701,519)	($6,549,357)	($8,851,076)	($6,190,755)	($4,716,820)	($3,101,107)	($3,484,994)	($4,826,707)	($2,968,118)	($1,792,000)	($3,741,229)	($5,638,407)	($55,562,090)
6	Gains from Off-System Sales (Per A6)	($876,040)	($1,741,631)	($2,183,089)	($1,053,380)	($1,015,087)	($688,662)	($793,680)	($588,750)	($278,750)	($312,500)	($675,000)	($1,277,500)	($11,484,069)
7	Fuel Cost of Purchased Power (Per A7)	$7,594,732	$6,358,940	$3,174,645	$14,997,896	$15,862,340	$24,618,502	$21,479,018	$16,190,014	$17,178,160	$14,461,104	$9,027,553	$8,443,059	$159,385,962
8	Energy Payments to Qualifying Facilities (Per A8)	$1,679,537	$1,308,964	$6,001,429	$9,692,457	$10,992,302	$11,182,480	$9,314,906	$14,505,666	$15,353,663	$10,077,669	$5,485,671	$3,385,672	$98,980,415
9	Energy Cost of Economy Purchases (Per A9)	$98,806	$63,673	$148,556	$1,639,283	$121,100	$186,471	$137,962	$500,000	$1,350,000	$1,225,000	$56,000	$44,000	$5,570,851
10	Total Fuel Costs & Net Power Transactions	$226,713,811	$208,908,774	$234,022,458	$288,124,017	$299,970,871	$321,120,295	$310,005,358	$329,527,820	$319,557,546	$292,809,745	$226,935,661	$227,222,880	$3,284,919,237
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs	$0	$0	$0	$20,622	$21,401	$28,231	$33,219	$32,288	$30,904	$33,672	$30,904	$32,288	$263,527
14	Variable Power Plant O&M Costs over 514,000 MW Threshold (Per A6)	$0	$0	$364,700	$315,395	$227,805	$125,549	$155,543	$113,250	$52,850	$60,400	$151,000	$286,900	$1,853,392
15	Total			364,700	336,017	249,206	153,780	188,762	145,538	83,754	94,072	181,904	319,188	2,116,919
16	**Adjustments to Fuel Cost**													
17	Sales to City of Key West (CKW)	($664,908)	($570,246)	($522,829)	($597,082)	($689,211)	($801,246)	$0	$0	$0	$0	$0	$0	($3,845,522)
18	Energy Imbalance Fuel Revenues	$56,481	$82,535	$48,854	$75,548	$65,257	$47,061	$47,948	$0	$0	$0	$0	$0	$423,684
19	Inventory Adjustments	($106,047)	($4,083,681)	$168,325	($88,560)	($285,132)	($28,899)	($78,905)	$0	$0	$0	$0	$0	($4,502,899)
20	Non Recoverable Oil/Tank Bottoms	$0	($718,392)	$452,505	$0	$189	($189)	$1,663,517	$0	$0	$0	$0	$0	$1,397,630
21	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,013	$287,849,940	$299,311,180	$320,490,802	$311,826,680	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,280,509,049
22	**Jurisdictional kWh Sales**													
23	Jurisdictional kWh Sales	7,684,412,091	7,108,916,875	6,977,292,798	7,671,972,198	8,616,263,762	9,110,063,405	9,724,266,549	10,080,997,264	9,763,403,645	9,104,618,770	8,255,228,566	8,067,004,659	102,164,440,582
24	Sale for Resale (excluding CKW) [2]	148,696,550	152,935,981	143,064,345	153,595,635	171,792,467	176,313,367	189,064,624	209,487,317	208,827,684	192,550,041	174,526,607	149,677,379	2,070,531,997
25	Sub-Total Sales (excluding CKW)	7,833,108,641	7,261,852,856	7,120,357,143	7,825,567,833	8,788,056,229	9,286,376,772	9,913,331,173	10,290,484,581	9,972,231,329	9,297,168,811	8,429,755,173	8,216,682,038	104,234,972,579
26														
27	**Jurisdictional % of Total Sales (Line 23/25)**	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01359%
28	**True-up Calculation**													
29	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$235,363,510	$216,081,517	$211,924,637	$229,504,273	$251,555,289	$267,491,971	$287,935,348	$297,175,299	$287,813,033	$268,392,872	$243,353,902	$237,805,294	$3,034,396,944
30	**Fuel Adjustment Revenues Not Applicable to Period**													
31	Prior Period True-up (Collected)/Refunded This Period [3]	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$4,007,108	$48,085,296
32	GPIF, Net of Revenue Taxes [4]	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,530)	($641,531)	($641,531)	($641,531)	($641,531)	($641,531)	($7,698,365)
33	Jurisdictional Fuel Revenues Applicable to Period	$238,729,088	$219,447,095	$215,290,215	$232,869,851	$254,920,867	$270,857,549	$291,300,926	$300,540,876	$291,178,610	$271,758,449	$246,719,479	$241,170,871	$3,074,783,875
34	Adjusted Total Fuel Costs & Net Power Transactions	$225,999,337	$203,618,990	$234,534,013	$287,849,940	$299,311,180	$320,490,802	$311,826,680	$329,673,358	$319,641,300	$292,903,816	$227,117,565	$227,542,068	$3,280,509,049
35	Jurisdictional Sales % of Total kWh Sales (Line 27)	98.10169%	97.89398%	97.99077%	98.03726%	98.04516%	98.10138%	98.09282%	97.96426%	97.90591%	97.92894%	97.92964%	98.17837%	98.01359%
36	Juris. Total Fuel Costs & Net Power Trans. (Line 34xLine35x1.00081)	$221,888,753	$199,492,191	$230,007,841	$282,428,776	$293,697,828	$314,660,568	$306,127,346	$323,223,665	$313,201,211	$287,069,941	$222,595,570	$223,578,045	$3,217,971,736
37	True-up Provision for the Month - Over/(Under) Recovery (Line 33 - Line 36)	$16,840,334	$19,954,904	($14,717,626)	($49,558,925)	($38,776,961)	($43,803,020)	($14,826,420)	($22,682,789)	($22,022,601)	($15,311,492)	$24,123,908	$17,592,827	($143,187,861)
38	Interest Provision for the Month	$2,912	$5,096	$4,722	$1,789	($1,335)	($3,612)	($4,579)	($5,118)	($6,218)	($7,164)	($7,147)	($6,445)	($27,098)
39	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	$48,085,296	$60,921,435	$76,874,326	$58,154,314	$4,590,070	($38,195,333)	($86,009,073)	($104,847,181)	($131,542,196)	($157,578,123)	($176,903,887)	($156,794,234)	$48,085,296
40	Deferred True-up Beginning of Period - Over/(Under) Recovery [5]	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)	($4,550,654)
41	Prior Period True-up Collected/(Refunded) This Period [3]	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($4,007,108)	($48,085,296)
42	End of Period Net True-up Amount Over/(Under) Recovery (Lines 37 through 41)	$56,370,780	$72,323,673	$53,603,660	$39,416	($42,745,988)	($90,559,727)	($109,397,834)	($136,092,850)	($162,128,777)	($181,454,541)	($161,344,888)	($147,765,614)	($147,765,613)
43	% Net (Under)/Over Recovery													
44														

45 [1] January through June Actuals include various adjustments as noted on the A-Schedules.

46 [2] Billed KWH includes all wholesale customers except CKW.

47 [3] Prior Period 2011/2012 Net True-up.

48 [4] Generation Performance Incentive Factor is (($7,703,912/12) x 99.9280%) - See Order No. PSC-12-0664-FOF-EI.

49 [5] Deferred 2012 Final True-up.

50

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR

SCHEDULE: E1-C

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Annual Total
1. TOTAL AMOUNT OF ADJUSTMENTS	$168,445,583
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$20,679,970
B. TRUE-UP (OVER)/UNDER RECOVERED	$147,765,613
2. TOTAL JURISDICTIONAL SALES (MWH)	105,843,225
3. ADJUSTMENT FACTORS (cents/kWh)	0.1591
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0195
B. TRUE-UP FACTOR	0.1396

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF MARGINAL TIME OF USE MULTIPLIERS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	E1-D Schedule - Marginal	Jan - 2014	Feb - 2014	Mar - 2014	Apr - 2014	May - 2014	Jun - 2014	Jul - 2014	Aug - 2014	Sep - 2014	Oct - 2014	Nov - 2014	Dec - 2014	Total
1	Full Year (January - December)													
2	On-Peak Period													
3	System MWH Requirements	2,412,752	2,106,898	2,054,363	2,998,055	3,315,018	3,438,876	3,919,931	3,653,625	3,742,709	3,378,511	1,978,702	2,359,988	35,359,428
4	Marginal Cost	$81,719,910	$70,370,393	$61,610,346	$184,920,032	$138,468,302	$304,031,027	$360,516,054	$342,746,561	$329,470,673	$190,615,591	$63,239,316	$74,103,623	$2,201,811,830
5	Average Marginal Cost (¢/kWh)	3.387	3.340	2.999	6.168	4.177	8.841	9.197	9.381	8.803	5.642	3.196	3.140	6.227
6	Off-Peak Period													
7	System MWH Requirements	6,370,148	5,774,237	6,795,526	5,978,958	6,993,994	7,361,504	7,758,024	8,064,526	7,191,462	6,907,162	6,790,379	6,592,659	82,578,579
8	Marginal Cost	$181,421,815	$161,909,605	$228,601,495	$189,353,600	$224,157,508	$328,764,769	$330,026,341	$313,064,899	$318,366,023	$261,021,652	$201,470,545	$193,758,248	$2,931,916,499
9	Average Marginal Cost (¢/kWh)	2.848	2.804	3.364	3.167	3.205	4.466	4.254	3.882	4.427	3.779	2.967	2.939	3.550
10	Total Period													
11	System MWH Requirements	8,782,900	7,881,135	8,849,889	8,977,013	10,309,012	10,800,380	11,677,955	11,718,151	10,934,171	10,285,673	8,769,081	8,952,647	117,938,007
12	Marginal Cost	$263,141,725	$232,279,999	$290,211,841	$374,273,632	$362,625,810	$632,795,796	$690,542,395	$655,811,461	$647,836,696	$451,637,243	$264,709,861	$267,861,871	$5,133,728,329
13	Average Marginal Cost (¢/kWh)	2.996	2.947	3.279	4.169	3.518	5.859	5.913	5.597	5.925	4.391	3.019	2.992	4.353
14														
15	Full Year Multiplier													
16	On-Peak Period													
17	Marginal Fuel Cost Weighting Multiplier													1.431
18	Off-Peak Period													
19	Marginal Fuel Cost Weighting Multiplier													0.816
20	Average													
21	Marginal Fuel Cost Weighting Multiplier													1.000
22														
23														
24														
25														
26														
27														
28														
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39														

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Jun - 2014	(3) Jul - 2014	(4) Aug - 2014	(5) Sep - 2014	(6) Total
1	June - September					
2	*On-Peak Period*					
3	System MWH Requirements	1,576,655	1,801,555	1,676,044	1,734,431	6,788,685
4	Marginal Cost	$143,617,504	$178,894,412	$175,230,400	$174,206,250	$671,948,565
5	Average Marginal Cost (¢/kWh)	9.109	9.930	10.455	10.044	9.898
6	*Off-Peak Period*					
7	System MWH Requirements	9,223,725	9,876,400	10,042,107	9,199,740	38,341,972
8	Marginal Cost	$449,564,357	$457,178,556	$424,078,179	$425,763,967	$1,756,585,058
9	Average Marginal Cost (¢/kWh)	4.874	4.629	4.223	4.628	4.581
10	*Total Period*					
11	System MWH Requirements	10,800,380	11,677,955	11,718,151	10,934,171	45,130,657
12	Marginal Cost	$593,181,860	$636,072,968	$599,308,579	$599,970,217	$2,428,533,624
13	Average Marginal Cost (¢/kWh)	5.492	5.447	5.114	5.487	5.381
14						
15	June - September Multiplier					
16	*On-Peak Period*					
17	Marginal Fuel Cost Weighting Multiplier					1.839
18	*Off-Peak Period*					
19	Marginal Fuel Cost Weighting Multiplier					0.851
20	*Average*					
21	Marginal Fuel Cost Weighting Multiplier					1.000
22						
23						
24	Note: Totals may not add due to rounding.					
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						

FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	3.383	1.00293	3.067
A	RS-1 all additional kWh	3.383	1.00293	4.067
A	GS-1, SL-2, GSCU-1, WIES-1	3.383	1.00293	3.393
A-1	SL-1, OL-1, PL-1 [1]	3.093	1.00293	3.102
B	GSD-1	3.383	1.00284	3.393
C	GSLD-1, CS-1	3.383	1.00186	3.389
D	GSLD-2, CS-2, OS-2, MET	3.383	0.99253	3.358
E	GSLD-3, CS-3	3.383	0.96479	3.264
A	GST-1 On-Peak	4.841	1.00293	4.855
	GST-1 Off-Peak	2.761	1.00293	2.769
A	RTR-1 On-Peak	-	-	1.462
	RTR-1 Off-Peak	-	-	(0.624)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.841	1.00283	4.855
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.761	1.00283	2.769
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.841	1.00186	4.850
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.761	1.00186	2.766
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.841	0.99328	4.808
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.761	0.99328	2.742
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.841	0.96479	4.671
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.761	0.96479	2.664
F	CILC-1(D), ISST-1(D) On-Peak	4.841	0.99253	4.805
	CILC-1(D), ISST-1(D) Off-Peak	2.761	0.99253	2.740

[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	6.221	1.00284	6.239
	GSD(T)-1 Off-Peak	2.879	1.00284	2.887
C	GSLD(T)-1 On-Peak	6.221	1.00186	6.233
	GSLD(T)-1 Off-Peak	2.879	1.00186	2.884
D	GSLD(T)-2 On-Peak	6.221	0.99328	6.179
	GSLD(T)-2 Off-Peak	2.879	0.99328	2.860

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
2014 PROJECTED ENERGY LOSSES BY RATE CLASS

Line No.	(1) Rate Class/Voltage Level	(2) Delivered MWH Sales	(3) Expansion Factor	(4) Delivered Energy at Generation	(5) Delivered Efficiency	(6) Losses	(7) Fuel Cost Recovery Multiplier
1	RS(T)-1						
2	Secondary	55,468,625	1.058576	58,717,738	0.944666	3,249,113	
3	**Total**	55,468,625	1.058576	58,717,738	0.944666	3,249,113	1.00293
4							
5	CILC-1D						
6	Primary	1,042,588	1.028631	1,072,438	0.972165	29,851	
7	Secondary	1,801,565	1.058576	1,907,093	0.944666	105,528	
8	**Total**	2,844,152	1.047599	2,979,531	0.954564	135,379	0.99253
9							
10	CILC-1G						
11	Primary	1,750	1.028631	1,800	0.972165	50	
12	Secondary	190,631	1.058576	201,798	0.944666	11,166	
13	**Total**	192,381	1.058303	203,598	0.944909	11,216	1.00267
14							
15	CILC-1T						
16	Transmission	1,314,661	1.018323	1,338,750	0.982006	24,089	
17	**Total**	1,314,661	1.018323	1,338,750	0.982006	24,089	0.96479
18							
19	GS(T)-1						
20	Secondary	6,127,209	1.058576	6,486,115	0.944666	358,905	
21	**Total**	6,127,209	1.058576	6,486,115	0.944666	358,905	1.00293
22							
23	GSCU-1						
24	Secondary	24,089	1.058576	25,500	0.944666	1,411	
25	**Total**	24,089	1.058576	25,500	0.944666	1,411	1.00293
26							
27	GSD(T)-1						
28	Primary	86,102	1.028631	88,567	0.972165	2,465	
29	Secondary	25,680,281	1.058576	27,184,521	0.944666	1,504,240	
30	**Total**	25,766,383	1.058476	27,273,088	0.944755	1,506,705	1.00284
31							
32	GSLD(T)-1						
33	Primary	399,862	1.028631	411,311	0.972165	11,449	
34	Secondary	10,207,414	1.058576	10,805,320	0.944666	597,906	
35	**Total**	10,607,276	1.057447	11,216,631	0.945674	609,355	1.00186
36							
37	GSLD(T)-2						
38	Primary	840,414	1.028631	864,477	0.972165	24,062	
39	Secondary	1,631,363	1.058576	1,726,921	0.944666	95,558	
40	**Total**	2,471,777	1.048395	2,591,398	0.953839	119,620	0.99328
41							
42	GSLD(T)-3						
43	Transmission	177,469	1.018323	180,721	0.982006	3,252	
44	**Total**	177,469	1.018323	180,721	0.982006	3,252	0.96479
45							
46	MET						
47	Primary	92,674	1.028631	95,327	0.972165	2,653	
48	**Total**	92,674	1.028631	95,327	0.972165	2,653	0.97456
49							
50	OL-1						
51	Secondary	98,770	1.058576	104,556	0.944666	5,786	
52	**Total**	98,770	1.058576	104,556	0.944666	5,786	1.00293
53							
54	OS-2						
55	Primary	11,761	1.028631	12,098	0.972165	337	

FLORIDA POWER & LIGHT COMPANY
2014 PROJECTED ENERGY LOSSES BY RATE CLASS

Line No.	Rate Class/Voltage Level	(1) Delivered MWH Sales	(2) Expansion Factor	(3) Delivered Energy at Generation	(4) Delivered Efficiency	(5) Losses	(6) Fuel Cost Recovery Multiplier
1	**Total**	11,761	1.028631	12,098	0.972165	337	0.97456
2							
3	SL-1						
4	Secondary	531,937	1.058576	563,096	0.944666	31,159	
5	**Total**	531,937	1.058576	563,096	0.944666	31,159	1.00293
6							
7	SL-2						
8	Secondary	32,554	1.058576	34,461	0.944666	1,907	
9	**Total**	32,554	1.058576	34,461	0.944666	1,907	1.00293
10							
11	SST-DST						
12	Primary	9,858	1.028631	10,140	0.972165	282	
13	**Total**	9,858	1.028631	10,140	0.972165	282	0.97456
14							
15	SST-TST						
16	Transmission	88,606	1.018323	90,229	0.982006	1,624	
17	**Total**	88,606	1.018323	90,229	0.982006	1,624	0.96479
18							
19	Total Retail						
20	**Total**	105,860,183	1.057272	111,922,976	0.945831	6,062,793	1.00169
21							
22	FKEC						
23	Transmission	772,116	1.018323	786,264	0.982006	14,148	
24	**Total**	772,116	1.018323	786,264	0.982006	14,148	0.96479
25							
26	SEMINOLE						
27	Transmission	430,534	1.018323	438,423	0.982006	7,889	
28	**Total**	430,534	1.018323	438,423	0.982006	7,889	0.96479
29							
30	LCEC						
31	Transmission	3,787,145	1.018323	3,856,538	0.982006	69,393	
32	**Total**	3,787,145	1.018323	3,856,538	0.982006	69,393	0.96479
33							
34	WAUCHULA						
35	Transmission	65,911	1.018323	67,118	0.982006	1,208	
36	**Total**	65,911	1.018323	67,118	0.982006	1,208	0.96479
37							
38	Blountstown						
39	Transmission	40,814	1.018323	41,562	0.982006	748	
40	**Total**	40,814	1.018323	41,562	0.982006	748	0.96479
41							
42	Total Wholesale						
43	**Total**	5,096,520	1.018323	5,189,905	0.982006	93,385	0.96479
44							
45	Total Company						
46	**Total**	110,956,703	1.055483	117,112,881	0.947434	6,156,178	1.00000
47							
48	Company Use						
49	**Total**	129,213	1.058576	136,782	0.944666	7,569	1.00293
50							
51	Total FPL						
52	**Total**	111,085,916	1.055486	117,249,663	0.947431	6,163,747	1.00000
53							
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FLORIDA POWER & LIGHT COMPANY
2014 PROJECTED ENERGY LOSSES BY RATE CLASS GROUP

Line No.	(1) RATE CLASS GROUPS	(2) Delivered MWH Sales	(3) Expansion Factor	(4) Delivered Energy at Generation	(5) Delivered Efficiency	(6) Losses	(7) Fuel Cost Recovery Multiplier
1	GSD1/GSDT1/HLFT1	25,766,383	1.058476	27,273,088	0.944755	1,506,705	1.00284
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,607,276	1.057447	11,216,631	0.945674	609,355	1.00186
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,471,777	1.048395	2,591,398	0.953839	119,620	0.99328
4	GSLD3/GSLDT3/CS3/CST3	177,469	1.018323	180,721	0.982006	3,252	0.96479
5	CILC D/CILC G	3,036,534	1.048277	3,183,129	0.953946	146,595	0.99317
6	OL1/SL1/PL1	630,708	1.058576	667,652	0.944666	36,944	1.00293
7	SL2, GSCU1	56,643	1.058576	59,961	0.944666	3,318	1.00293
8	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	25,958,764	1.058474	27,476,686	0.944756	1,517,922	1.00283
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,576,212	1.047593	2,698,822	0.954569	122,611	0.99253
10	GSLD-3/GSLDT-3/CS-3/CST-3/CILC-1T	1,492,131	1.018323	1,519,471	0.982006	27,341	0.96479
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FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Fuel Cost of System Generation	$233,108,385	$213,044,367	$257,918,712	$259,343,506	$279,253,240	$295,856,825	$321,498,280	$321,451,323	$298,810,379	$291,192,917	$233,978,087	$242,685,535	$3,248,141,556
2	Nuclear Fuel Disposal	2,409,819	2,176,613	1,587,537	1,860,399	2,347,859	2,272,121	2,347,859	2,347,859	2,146,193	1,826,155	2,332,085	2,409,819	26,064,319
3	RBEC Fuel Savings	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	82,000,000
4	Fuel Cost of Power Sold	(5,739,770)	(9,106,079)	(10,893,920)	(7,980,423)	(5,760,820)	(5,833,323)	(6,602,020)	(4,047,920)	(1,737,073)	(1,970,620)	(3,479,923)	(6,536,420)	(69,688,315)
5	Gain on Economy Sales	(993,750)	(1,657,500)	(1,948,750)	(1,193,750)	(901,250)	(650,000)	(823,750)	(565,000)	(203,750)	(290,000)	(637,500)	(1,215,000)	(11,080,000)
6	Fuel Cost of Purchased Power	9,032,496	8,624,221	9,398,040	9,481,790	13,524,421	15,397,625	16,147,779	15,798,587	16,191,274	13,504,351	8,721,822	8,501,088	144,323,495
7	Qualifying Facilities	9,945,865	8,880,867	10,309,866	5,997,865	10,849,865	13,256,860	14,016,861	13,746,860	13,771,859	9,839,862	6,976,866	8,973,866	126,567,361
8	Energy Cost of Economy Purchases	197,461	85,278	86,206	519,450	155,794	3,005,537	3,824,412	2,947,914	1,805,718	715,344	29,606	30,818	13,403,538
9	Total Fuel & Net Power Transactions	$254,793,840	$228,881,101	$273,291,024	$274,862,170	$306,302,441	$330,138,979	$357,242,754	$358,512,956	$337,617,933	$321,651,343	$254,754,376	$261,683,039	$3,559,731,955
10														
11	Incremental Personnel, Software and Hardware Costs	33,432	29,280	31,536	32,961	32,961	31,536	34,387	31,536	32,961	34,387	30,110	34,387	389,472
12	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	0	326,160	279,350	203,850	128,350	143,450	105,700	37,750	60,400	151,000	286,900	1,722,910
13	Total	33,432	29,280	357,696	312,311	236,811	159,886	177,837	137,236	70,711	94,787	181,110	321,287	2,112,382
14	Adjusted Total Fuel & Net Power Transactions	254,827,272	228,910,381	273,648,719	275,174,481	306,539,252	330,298,864	357,420,590	358,650,191	337,688,644	321,746,129	254,935,486	262,004,326	3,561,844,337
15														
16	System MWH Sales	8,985,918	7,947,739	7,864,510	7,931,770	9,091,100	9,818,071	10,760,888	10,705,544	10,396,265	9,730,435	8,866,980	8,668,474	110,767,695
17														
18	Cost per KWH (¢/KWH)	2.8359	2.8802	3.4795	3.4693	3.3719	3.3642	3.3215	3.3501	3.2482	3.3066	2.8751	3.0225	3.2156
19	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
20	Jurisdictional Cost (¢/KWH)	2.8406	2.8851	3.4854	3.4751	3.3776	3.3699	3.3271	3.3558	3.2537	3.3122	2.8800	3.0276	3.2210
21	True-Up (¢/KWH)	0.1392	0.1619	0.1633	0.1628	0.1411	0.1311	0.1199	0.1211	0.1249	0.1336	0.1467	0.1491	0.1396
22	Total (¢/KWH)	2.9798	3.0470	3.6487	3.6379	3.5187	3.5010	3.4470	3.4769	3.3786	3.4458	3.0267	3.1767	3.3606
23	Revenue Tax Factor (0.00072)	0.0021	0.0022	0.0026	0.0026	0.0025	0.0025	0.0025	0.0025	0.0024	0.0025	0.0022	0.0023	0.0024
24	Recovery Factor Adjusted for Taxes (¢/KWH)	2.9819	3.0492	3.6513	3.6405	3.5212	3.5035	3.4495	3.4794	3.3810	3.4483	3.0289	3.1790	3.3630
25	GPIF (¢/KWH)	0.0195	0.0227	0.0229	0.0228	0.0197	0.0184	0.0168	0.0170	0.0175	0.0187	0.0205	0.0209	0.0195
26	Recovery Factor including GPIF (¢/KWH)	3.0014	3.0719	3.6742	3.6633	3.5409	3.5219	3.4663	3.4964	3.3985	3.4670	3.0494	3.1999	3.3825
27														
28	Recovery Factor Rounded to .001 (¢/KWH)	3.001	3.072	3.674	3.663	3.541	3.522	3.466	3.496	3.399	3.467	3.049	3.200	3.383
29														
30	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH MAY 2014

Line No.	(1)	(2) RS-1 Standard	(3) Proposed Inverted Fuel Factors	(4) Target Fuel Revenues	(5) Rounded
1	First 1000 KWH	37,388,852,427	0.030672	$1,146,776,697.45	3.067
2	All Additional KWH	18,070,887,116	0.040672	$734,972,265.24	4.067
3	Total KWH	55,459,739,543		$1,881,748,962.69	
4					
5	Avg Fuel Factor	3.383			
6	RS-1 Loss Multiplier	1.00293			
7	Average Fuel Factor	3.393			
8					
9	Target Fuel Revenues	$1,881,748,962.69			
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	**Fuel Cost of System Net Generation ($)**													
2	Heavy Oil	1,183,949	230,112	965,877	3,395,847	949,606	7,736,081	9,344,546	8,068,395	5,036,187	3,523,855	0	0	40,434,454
3	Light Oil	72,089	16,248	0	405,481	0	702,542	281,798	92,183	0	0	0	0	1,570,341
4	Coal	10,094,722	7,475,072	1,689,950	4,791,987	13,244,647	14,871,995	15,387,859	13,779,124	13,478,346	14,200,718	11,664,222	11,967,065	132,645,707
5	Gas	204,229,626	189,491,935	246,044,886	237,037,191	247,564,987	255,616,206	278,990,077	282,017,622	264,328,846	260,238,344	205,137,865	212,968,470	2,883,666,055
6	Nuclear	17,528,000	15,831,000	9,218,000	13,713,000	17,494,000	16,930,000	17,494,000	17,494,000	15,967,000	13,230,000	17,176,000	17,750,000	189,825,000
7	**Total Fuel Cost of System Net Generatic**	233,108,385	213,044,367	257,918,712	259,343,506	279,253,240	295,856,825	321,498,280	321,451,323	298,810,379	291,192,917	233,978,087	242,685,535	3,248,141,556
8														
9	**System Net Generation (MWH)**													
10	Heavy Oil	7,312	1,147	3,961	17,062	3,523	44,104	54,505	47,727	31,241	22,174	0	0	232,756
11	Light Oil	568	58	0	1,356	0	1,923	799	285	0	0	0	0	4,989
12	Coal	360,814	266,997	42,006	166,457	479,144	541,611	559,821	493,468	480,014	511,615	421,797	431,898	4,755,642
13	Gas	5,531,628	5,122,080	6,947,787	6,588,154	6,816,431	7,098,551	7,824,570	7,943,964	7,379,351	7,217,747	5,564,017	5,692,688	79,726,968
14	Nuclear	2,567,188	2,318,753	1,691,208	1,981,889	2,501,181	2,420,498	2,501,181	2,501,181	2,286,346	1,945,409	2,484,377	2,567,188	27,766,399
15	Solar	9,217	10,455	18,398	21,524	21,836	20,004	19,439	18,279	15,996	14,558	11,251	9,668	190,625
16	**Total System Net Generation (MWH)**	8,476,727	7,719,490	8,703,360	8,776,442	9,822,115	10,126,691	10,960,315	11,004,904	10,192,948	9,711,503	8,481,442	8,701,442	112,677,379
17														
18	**Units of Fuel Burned (Unit)** [a]													
19	Heavy Oil	12,664	2,462	10,334	36,211	10,115	82,446	99,585	85,903	54,000	37,670			431,390
20	Light Oil	719	134		3,344		5,754	2,308	755					13,014
21	Coal	211,828	157,539	22,108	98,306	282,396	318,634	329,511	289,440	280,917	302,470	249,967	255,871	2,798,987
22	Gas	38,202,064	35,717,664	49,002,821	46,704,292	48,473,113	50,657,325	55,715,799	56,296,870	52,454,740	51,014,543	38,195,941	38,921,298	561,356,468
23	Nuclear	27,109,985	24,486,449	17,963,668	21,383,576	27,094,244	26,220,236	27,094,244	27,094,244	24,718,736	20,873,643	26,235,473	27,109,985	297,384,483
24	Total Units of Fuel Burned (Unit)													
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	81,051	15,755	66,138	231,744	64,736	527,658	637,342	549,780	345,598	241,091	0	0	2,760,893
28	Light Oil	4,191	740	0	19,498	0	33,542	13,459	4,363	0	0	0	0	75,793
29	Coal	3,830,354	2,843,485	486,370	1,792,987	5,080,381	5,721,878	5,915,057	5,225,738	5,080,521	5,421,670	4,465,673	4,570,318	50,434,432
30	Gas	38,202,064	35,717,664	49,002,821	46,704,292	48,473,113	50,657,325	55,715,799	56,296,870	52,454,740	51,014,543	38,195,941	38,921,298	561,356,468
31	Nuclear	27,109,985	24,486,449	17,963,668	21,383,576	27,094,244	26,220,236	27,094,244	27,094,244	24,718,736	20,873,643	26,235,473	27,109,985	297,384,483
32	**Total BTU Burned (MMBTU)**	69,227,645	63,064,093	67,518,997	70,132,097	80,712,474	83,160,639	89,375,901	89,170,995	82,599,595	77,550,947	68,897,087	70,601,601	912,012,069
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	93.4893	93.4654	93.4659	93.7794	93.8810	93.8321	93.8349	93.9245	93.2627	93.5454	0.0000	0.0000	93.7306
36	Light Oil	100.2625	121.2562	0.0000	121.2562	0.0000	122.0963	122.0963	122.0963	0.0000	0.0000	0.0000	0.0000	120.6655
37	Coal	47.6553	47.4490	76.4406	48.7456	46.9010	46.6742	46.6991	47.6061	47.9798	46.9492	46.6630	46.7699	47.3906
38	Gas	5.3460	5.3053	5.0210	5.0753	5.1073	5.0460	5.0074	5.0095	5.0392	5.1013	5.3707	5.4718	5.1370
39	Nuclear	0.6466	0.6465	0.5131	0.6413	0.6457	0.6457	0.6457	0.6457	0.6459	0.6338	0.6547	0.6547	0.6383
40	**Total Fuel Cost per Unit ($/Unit)**													
41														
42	**Generation Mix (%)**													
43	Heavy Oil	0.09%	0.01%	0.05%	0.19%	0.04%	0.44%	0.50%	0.43%	0.31%	0.23%	0.00%	0.00%	0.21%

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Light Oil	0.01%	0.00%	0.00%	0.02%	0.00%	0.02%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Coal	4.26%	3.46%	0.48%	1.90%	4.88%	5.35%	5.11%	4.48%	4.71%	5.27%	4.97%	4.96%	4.22%
3	Gas	65.26%	66.35%	79.83%	75.07%	69.40%	70.10%	71.39%	72.19%	72.40%	74.32%	65.60%	65.42%	70.76%
4	Nuclear	30.29%	30.04%	19.43%	22.58%	25.46%	23.90%	22.82%	22.73%	22.43%	20.03%	29.29%	29.50%	24.64%
5	Solar	0.11%	0.14%	0.21%	0.25%	0.22%	0.20%	0.18%	0.17%	0.16%	0.15%	0.13%	0.11%	0.17%
6	**Total Generation Mix (%)**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
7														
8	**Fuel Cost per MMBTU ($/MMBTU)**													
9	Heavy Oil	14.6075	14.6056	14.6040	14.6534	14.6689	14.6612	14.6617	14.6757	14.5724	14.6163	0.0000	0.0000	14.6454
10	Light Oil	17.2008	21.9572	0.0000	20.7960	0.0000	20.9451	20.9375	21.1283	0.0000	0.0000	0.0000	0.0000	20.7188
11	Coal	2.6355	2.6288	3.4746	2.6726	2.6070	2.5991	2.6015	2.6368	2.6529	2.6193	2.6120	2.6184	2.6301
12	Gas	5.3460	5.3053	5.0210	5.0753	5.1073	5.0460	5.0074	5.0095	5.0392	5.1013	5.3707	5.4718	5.1370
13	Nuclear	0.6466	0.6465	0.5131	0.6413	0.6457	0.6457	0.6457	0.6457	0.6459	0.6338	0.6547	0.6547	0.6383
14														
15	**BTU Burned per KWH (BTU/KWH)**													
16	Heavy Oil	11,085	13,736	16,697	13,582	18,375	11,964	11,693	11,519	11,062	10,873	0	0	11,862
17	Light Oil	7,379	12,759	0	14,379	0	17,443	16,845	15,309	0	0	0	0	15,192
18	Coal	10,616	10,650	11,579	10,771	10,603	10,565	10,566	10,590	10,584	10,597	10,587	10,582	10,605
19	Gas	6,906	6,973	7,053	7,089	7,111	7,136	7,121	7,087	7,108	7,068	6,865	6,837	7,041
20	Nuclear	10,560	10,560	10,622	10,789	10,833	10,833	10,833	10,833	10,811	10,730	10,560	10,560	10,710
21														
22	**Generated Fuel Cost per KWH (cents/KWH)**													
23	Heavy Oil	16.1919	20.0621	24.3847	19.9030	26.9545	17.5405	17.1444	16.9053	16.1204	15.8918	0.0000	0.0000	17.3720
24	Light Oil	12.6917	28.0144	0.0000	29.9027	0.0000	36.5337	35.2689	32.3448	0.0000	0.0000	0.0000	0.0000	31.4761
25	Coal	2.7978	2.7997	4.0231	2.8788	2.7642	2.7459	2.7487	2.7923	2.8079	2.7757	2.7654	2.7708	2.7892
26	Gas	3.6920	3.6995	3.5413	3.5979	3.6319	3.6010	3.5656	3.5501	3.5820	3.6055	3.6869	3.7411	3.6169
27	Nuclear	0.6828	0.6827	0.5451	0.6919	0.6994	0.6994	0.6994	0.6994	0.6984	0.6801	0.6914	0.6914	0.6837
28	**Total Generated Fuel Cost per KWH (ce**	2.7500	2.7598	2.9634	2.9550	2.8431	2.9216	2.9333	2.9210	2.9315	2.9984	2.7587	2.7890	2.8827
29														
30														
31	[(a)] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
32														
33														
34														
35														
36														
37														
38														
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40														
41														
42														
43														

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jan - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		945,260					6,154,313	1,000,000	6,154,313	32,532,832	3.44	5.29
5	Plant Unit Info	1,355	945,260	93.8%	95.8%	93.8%	6,511			6,154,313	32,532,832	3.44	
6	*Desoto Solar*												
7	Solar		3,151					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,151	16.9%		37.0%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		544,169					3,965,313	1,000,000	3,965,313	21,237,565	3.90	5.36
18	Plant Unit Info	1,435	544,169	51.0%	94.9%	84.3%	7,287			3,965,313	21,237,565	3.90	
19	*Fort Myers 3A B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		1,201					13,014	1,000,000	13,014	70,924	5.91	5.45
22	Plant Unit Info	314	1,201	1.0%	95.5%	95.5%	10,839			13,014	70,924	5.91	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		568					719	5,828,929	4,191	72,089	12.69	100.26
29	Gas		10,578					84,017	1,000,000	84,017	454,768	4.30	5.41
30	Plant Unit Info	442	11,146	3.4%	94.0%	64.7%	7,914			88,208	526,857	4.73	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		10,346					82,030	1,000,000	82,030	444,748	4.30	5.42
34	Plant Unit Info	442	10,346	3.2%	94.6%	68.9%	7,929			82,030	444,748	4.30	
35	*Manatee 1*												
36	Heavy Oil		2,419					4,354	6,400,322	27,867	410,169	16.96	94.21
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	795	2,419	0.4%	95.3%	76.1%	11,520			27,867	410,169	16.96	
2	*Manatee 2*												
3	Heavy Oil		2,195					4,007	6,400,549	25,647	377,480	17.20	94.21
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	795	2,195	0.4%	94.0%	69.0%	11,684			25,647	377,480	17.20	
6	*Manatee 3*												
7	Gas		443,800					3,148,205	1,000,000	3,148,205	16,871,676	3.80	5.36
8	Plant Unit Info	1,116	443,800	53.5%	94.6%	89.6%	7,094			3,148,205	16,871,676	3.80	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		2,087					3,397	6,400,353	21,742	312,770	14.99	92.07
15	Gas		1,527					20,703	1,000,000	20,703	110,824	7.26	5.35
16	Plant Unit Info	808	3,614	0.6%	82.0%	32.0%	11,744			42,445	423,595	11.72	
17	*Martin 3*												
18	Gas		16,750					127,458	1,000,000	127,458	681,507	4.07	5.35
19	Plant Unit Info	454	16,750	5.0%	94.8%	85.8%	7,609			127,458	681,507	4.07	
20	*Martin 4*												
21	Gas		14,987					114,658	1,000,000	114,658	612,997	4.09	5.35
22	Plant Unit Info	453	14,987	4.5%	94.0%	78.8%	7,651			114,658	612,997	4.09	
23	*Martin 8*												
24	Gas		697,802					4,812,747	1,000,000	4,812,747	25,795,721	3.70	5.36
25	Plant Unit Info	1,147	697,802	81.8%	94.9%	84.8%	6,897			4,812,747	25,795,721	3.70	
26	*Martin 8 Solar*												
27	Solar		4,882					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	4,882	8.8%		19.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,344	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		1,513					14,835	1,000,000	14,835	80,700	5.33	5.44
35	Plant Unit Info	251	1,513	0.8%	94.2%	75.4%	9,805			14,835	80,700	5.33	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		1,722					16,587	1,000,000	16,587	90,275	5.24	5.44
2	Plant Unit Info	255	1,722	0.9%	94.8%	84.5%	9,632			16,587	90,275	5.24	
3	*Sanford 4*												
4	Gas		78,797					584,976	1,000,000	584,976	3,130,857	3.97	5.35
5	Plant Unit Info	975	78,797	10.9%	94.7%	77.7%	7,424			584,976	3,130,857	3.97	
6	*Sanford 5*												
7	Gas		132,929					990,534	1,000,000	990,534	5,299,449	3.99	5.35
8	Plant Unit Info	994	132,929	18.0%	94.9%	78.7%	7,452			990,534	5,299,449	3.99	
9	*Scherer 4*												
10	Coal		272,271					165,972	16,999,976	2,821,520	6,574,415	2.41	39.61
11	Plant Unit Info	646	272,271	56.7%	93.1%	93.1%	10,363			2,821,520	6,574,415	2.41	
12	*St Johns 1O*												
13	Coal		42,212					22,171	22,000,361	487,770	1,702,040	4.03	76.77
14	Plant Unit Info	128	42,212	44.3%	94.0%	44.3%	11,555			487,770	1,702,040	4.03	
15	*St Johns 2O*												
16	Coal		46,331					23,685	21,999,747	521,064	1,818,267	3.92	76.77
17	Plant Unit Info	128	46,331	48.6%	93.2%	48.6%	11,247			521,064	1,818,267	3.92	
18	*St Lucie 1*												
19	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,956,000	0.68	0.66
20	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,956,000	0.68	
21	*St Lucie 2*												
22	Nuclear		623,845					6,379,606	1,000,000	6,379,606	4,026,000	0.65	0.63
23	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,226			6,379,606	4,026,000	0.65	
24	*Space Coast*												
25	Solar		1,184					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,184	15.9%		34.7%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		611					906	6,396,247	5,795	83,529	13.67	92.20
29	Gas		0					900	1,000,000	900	4,823	0.00	5.36
30	Plant Unit Info	380	611	0.2%	95.2%	80.3%	10,957			6,695	88,352	14.46	
31	*Turkey Point 3*												
32	Nuclear		604,258					6,568,489	1,000,000	6,568,489	4,284,000	0.71	0.65
33	Plant Unit Info	833	604,258	97.5%	97.5%	97.5%	10,870			6,568,489	4,284,000	0.71	
34	*Turkey Point 4*												
35	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,262,000	0.70	0.64
36	Plant Unit Info	843	611,511	97.5%	97.5%	97.5%	10,870			6,647,323	4,262,000	0.70	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		388,673					2,747,118	1,000,000	2,747,118	14,745,055	3.79	5.37
2	Plant Unit Info	1,138	388,673	45.9%	94.2%	87.1%	7,068			2,747,118	14,745,055	3.79	
3	*WCEC 01*												
4	Gas		752,253					5,145,664	1,000,000	5,145,664	27,689,962	3.68	5.38
5	Plant Unit Info	1,208	752,253	83.7%	95.5%	87.7%	6,840			5,145,664	27,689,962	3.68	
6	*WCEC 02*												
7	Gas		779,104					5,322,723	1,000,000	5,322,723	28,288,161	3.63	5.31
8	Plant Unit Info	1,202	779,104	87.1%	95.7%	87.1%	6,832			5,322,723	28,288,161	3.63	
9	*WCEC 03*												
10	Gas		710,218					4,856,270	1,000,000	4,856,270	26,086,780	3.67	5.37
11	Plant Unit Info	1,207	710,218	79.1%	95.5%	87.3%	6,838			4,856,270	26,086,780	3.67	
12	**System Totals**												
13	Plant Unit Info	25,886	8,476,727				8,167			69,227,645	233,108,385	2.75	
14													
15													
16													
17													
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19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Feb - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		636,582					4,142,626	1,000,000	4,142,626	21,731,160	3.41	5.25
5	Plant Unit Info	1,355	636,582	69.9%	71.9%	93.2%	6,508			4,142,626	21,731,160	3.41	
6	*Desoto Solar*												
7	Solar		3,593					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,593	21.4%		46.7%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		58					134	5,522,388	740	16,248	28.01	121.26
15	Plant Unit Info	690	58	0.0%	95.3%	8.4%	12,759			740	16,248	28.01	
16	*Fort Myers 2*												
17	Gas		638,354					4,618,451	1,000,000	4,618,451	24,550,935	3.85	5.32
18	Plant Unit Info	1,435	638,354	66.2%	94.9%	81.5%	7,235			4,618,451	24,550,935	3.85	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		4,802					52,054	1,000,000	52,054	278,370	5.80	5.35
22	Plant Unit Info	314	4,802	4.5%	95.5%	95.5%	10,839			52,054	278,370	5.80	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		26,439					210,187	1,000,000	210,187	1,125,686	4.26	5.36
30	Plant Unit Info	442	26,439	8.9%	80.6%	69.6%	7,950			210,187	1,125,686	4.26	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		32,376					257,259	1,000,000	257,259	1,378,468	4.26	5.36
34	Plant Unit Info	442	32,376	10.9%	81.1%	69.8%	7,946			257,259	1,378,468	4.26	
35	*Manatee 1*												
36	Heavy Oil		633					1,608	6,398,632	10,289	151,482	23.93	94.21
37	Gas		1,477					15,409	1,000,000	15,409	83,126	5.63	5.39

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	795	2,110	0.4%	95.3%	66.3%	12,182			25,698	234,608	11.12	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	795	0	0.0%	47.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		524,769					3,690,146	1,000,000	3,690,146	19,645,302	3.74	5.32
8	Plant Unit Info	1,116	524,769	70.0%	94.6%	84.4%	7,032			3,690,146	19,645,302	3.74	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		514					854	6,400,468	5,466	78,630	15.30	92.07
15	Gas		3,027					37,808	1,000,000	37,808	201,898	6.67	5.34
16	Plant Unit Info	808	3,541	0.7%	82.0%	27.4%	12,219			43,274	280,528	7.92	
17	*Martin 3*												
18	Gas		62,231					477,447	1,000,000	477,447	2,533,584	4.07	5.31
19	Plant Unit Info	454	62,231	20.4%	94.8%	75.3%	7,672			477,447	2,533,584	4.07	
20	*Martin 4*												
21	Gas		59,870					459,331	1,000,000	459,331	2,437,506	4.07	5.31
22	Plant Unit Info	453	59,870	19.7%	94.0%	73.9%	7,672			459,331	2,437,506	4.07	
23	*Martin 8*												
24	Gas		610,259					4,196,400	1,000,000	4,196,400	22,363,278	3.66	5.33
25	Plant Unit Info	1,147	610,259	79.2%	89.0%	80.2%	6,876			4,196,400	22,363,278	3.66	
26	*Martin 8 Solar*												
27	Solar		5,590					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	5,590	11.1%		24.2%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,344	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		2,992					29,299	1,000,000	29,299	156,991	5.25	5.36
35	Plant Unit Info	251	2,992	1.8%	90.9%	74.5%	9,793			29,299	156,991	5.25	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		2,982					29,168	1,000,000	29,168	156,205	5.24	5.36
2	Plant Unit Info	255	2,982	1.7%	91.4%	73.2%	9,780			29,168	156,205	5.24	
3	*Sanford 4*												
4	Gas		185,005					1,369,391	1,000,000	1,369,391	7,280,977	3.94	5.32
5	Plant Unit Info	975	185,005	28.2%	94.7%	84.7%	7,402			1,369,391	7,280,977	3.94	
6	*Sanford 5*												
7	Gas		262,455					1,935,902	1,000,000	1,935,902	10,287,296	3.92	5.31
8	Plant Unit Info	994	262,455	39.3%	94.9%	81.3%	7,376			1,935,902	10,287,296	3.92	
9	*Scherer 4*												
10	Coal		204,188					124,475	17,000,024	2,116,078	4,935,425	2.42	39.65
11	Plant Unit Info	646	204,188	47.1%	69.8%	92.8%	10,363			2,116,078	4,935,425	2.42	
12	*St Johns 1O*												
13	Coal		24,191					13,021	22,000,230	286,465	1,000,143	4.13	76.81
14	Plant Unit Info	128	24,191	28.1%	67.1%	39.3%	11,842			286,465	1,000,143	4.13	
15	*St Johns 2O*												
16	Coal		38,618					20,043	21,999,800	440,942	1,539,503	3.99	76.81
17	Plant Unit Info	128	38,618	44.8%	93.2%	44.8%	11,418			440,942	1,539,503	3.99	
18	*St Lucie 1*												
19	Nuclear		657,165					6,787,360	1,000,000	6,787,360	4,476,000	0.68	0.66
20	Plant Unit Info	1,003	657,165	97.5%	97.5%	97.5%	10,328			6,787,360	4,476,000	0.68	
21	*St Lucie 2*												
22	Nuclear		563,473					5,762,227	1,000,000	5,762,227	3,636,000	0.65	0.63
23	Plant Unit Info	860	563,473	97.5%	97.5%	97.5%	10,226			5,762,227	3,636,000	0.65	
24	*Space Coast*												
25	Solar		1,272					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,272	18.9%		41.3%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		945					12,763	1,000,000	12,763	68,262	7.22	5.35
30	Plant Unit Info	380	945	0.4%	95.2%	41.4%	13,508			12,763	68,262	7.22	
31	*Turkey Point 3*												
32	Nuclear		545,780					5,932,829	1,000,000	5,932,829	3,869,000	0.71	0.65
33	Plant Unit Info	833	545,780	97.5%	97.5%	97.5%	10,870			5,932,829	3,869,000	0.71	
34	*Turkey Point 4*												
35	Nuclear		552,335					6,004,033	1,000,000	6,004,033	3,850,000	0.70	0.64
36	Plant Unit Info	843	552,335	97.5%	97.5%	97.5%	10,870			6,004,033	3,850,000	0.70	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		159,627					1,135,963	1,000,000	1,135,963	6,048,022	3.79	5.32
2	Plant Unit Info	1,138	159,627	20.9%	38.7%	61.0%	7,116			1,135,963	6,048,022	3.79	
3	*WCEC 01*												
4	Gas		699,667					4,782,631	1,000,000	4,782,631	25,434,756	3.64	5.32
5	Plant Unit Info	1,208	699,667	86.2%	95.5%	87.3%	6,836			4,782,631	25,434,756	3.64	
6	*WCEC 02*												
7	Gas		700,025					4,778,994	1,000,000	4,778,994	25,124,581	3.59	5.26
8	Plant Unit Info	1,202	700,025	86.6%	95.7%	86.6%	6,827			4,778,994	25,124,581	3.59	
9	*WCEC 03*												
10	Gas		508,196					3,486,435	1,000,000	3,486,435	18,605,531	3.66	5.34
11	Plant Unit Info	1,207	508,196	62.6%	79.6%	75.2%	6,860			3,486,435	18,605,531	3.66	
12	**System Totals**												
13	Plant Unit Info	25,886	7,719,490				8,169			63,064,093	213,044,367	2.76	
14													
15													
16													
17													
18													
19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Mar - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		873,433					5,703,845	1,000,000	5,703,845	28,237,093	3.23	4.95
5	Plant Unit Info	1,355	873,433	86.6%	88.6%	87.5%	6,530			5,703,845	28,237,093	3.23	
6	*Desoto Solar*												
7	Solar		4,915					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,915	26.4%		48.8%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		891,517					6,429,698	1,000,000	6,429,698	32,279,581	3.62	5.02
18	Plant Unit Info	1,435	891,517	83.5%	94.9%	83.5%	7,212			6,429,698	32,279,581	3.62	
19	*Fort Myers 3A B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		22,211					239,350	1,000,000	239,350	1,219,715	5.49	5.10
22	Plant Unit Info	314	22,211	19.0%	95.5%	95.5%	10,776			239,350	1,219,715	5.49	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		108,853					859,804	1,000,000	859,804	4,377,487	4.02	5.09
30	Plant Unit Info	442	108,853	33.1%	94.0%	87.7%	7,899			859,804	4,377,487	4.02	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		116,308					917,110	1,000,000	917,110	4,665,282	4.01	5.09
34	Plant Unit Info	442	116,308	35.4%	94.6%	86.4%	7,885			917,110	4,665,282	4.01	
35	*Manatee 1*												
36	Heavy Oil		1,751					6,657	6,400,330	42,607	627,124	35.82	94.21
37	Gas		8,239					91,960	1,000,000	91,960	465,547	5.65	5.06

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	795	9,990	1.7%	95.3%	34.0%	13,470			134,567	1,092,670	10.94	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	795	0	0.0%	9.1%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		656,028					4,608,176	1,000,000	4,608,176	23,198,628	3.54	5.03
8	Plant Unit Info	1,116	656,028	79.0%	94.6%	83.6%	7,024			4,608,176	23,198,628	3.54	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		1,210					2,030	6,400,000	12,992	186,907	15.45	92.07
15	Gas		7,268					101,939	1,000,000	101,939	514,509	7.08	5.05
16	Plant Unit Info	808	8,478	1.4%	63.5%	25.0%	13,556			114,931	701,416	8.27	
17	*Martin 3*												
18	Gas		157,259					1,201,032	1,000,000	1,201,032	6,017,940	3.83	5.01
19	Plant Unit Info	454	157,259	46.5%	94.8%	91.4%	7,637			1,201,032	6,017,940	3.83	
20	*Martin 4*												
21	Gas		148,172					1,133,540	1,000,000	1,133,540	5,679,843	3.83	5.01
22	Plant Unit Info	453	148,172	44.0%	94.0%	89.4%	7,650			1,133,540	5,679,843	3.83	
23	*Martin 8*												
24	Gas		612,995					4,206,610	1,000,000	4,206,610	21,235,466	3.46	5.05
25	Plant Unit Info	1,147	612,995	71.9%	78.8%	74.7%	6,862			4,206,610	21,235,466	3.46	
26	*Martin 8 Solar*												
27	Solar		11,799					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	11,799	21.2%		29.9%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,344	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	251	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	255	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Sanford 4*												
4	Gas		400,302					2,978,262	1,000,000	2,978,262	14,968,676	3.74	5.03
5	Plant Unit Info	975	400,302	55.2%	94.7%	92.4%	7,440			2,978,262	14,968,676	3.74	
6	*Sanford 5*												
7	Gas		510,132					3,759,967	1,000,000	3,759,967	18,886,276	3.70	5.02
8	Plant Unit Info	994	510,132	69.0%	94.9%	82.5%	7,371			3,759,967	18,886,276	3.70	
9	*Scherer 4*												
10	Coal		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	646	0	0.0%	0.0%	0.0%	0			0	0	0.00	
12	*St Johns 1O*												
13	Coal		42,006					22,108	21,999,729	486,370	1,689,950	4.02	76.44
14	Plant Unit Info	128	42,006	44.0%	94.0%	44.0%	11,579			486,370	1,689,950	4.02	
15	*St Johns 2O*												
16	Coal		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	128	0	0.0%	0.0%	0.0%	0			0	0	0.00	
18	*St Lucie 1*												
19	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,956,000	0.68	0.66
20	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,956,000	0.68	
21	*St Lucie 2*												
22	Nuclear		40,248					411,590	1,000,000	411,590	0	0.00	0.00
23	Plant Unit Info	860	40,248	6.3%	6.3%	97.5%	10,226			411,590	0	0.00	
24	*Space Coast*												
25	Solar		1,684					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,684	22.7%		41.8%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		1,000					1,647	6,398,907	10,539	151,846	15.18	92.20
29	Gas		4,639					63,043	1,000,000	63,043	317,643	6.85	5.04
30	Plant Unit Info	380	5,639	2.0%	95.2%	30.3%	13,050			73,582	469,488	8.33	
31	*Turkey Point 3*												
32	Nuclear		311,875					3,390,188	1,000,000	3,390,188	0	0.00	0.00
33	Plant Unit Info	833	311,875	50.3%	50.3%	97.5%	10,870			3,390,188	0	0.00	
34	*Turkey Point 4*												
35	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,262,000	0.70	0.64
36	Plant Unit Info	843	611,511	97.5%	97.5%	97.5%	10,870			6,647,323	4,262,000	0.70	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		618,559					4,294,974	1,000,000	4,294,974	21,589,547	3.49	5.03
2	Plant Unit Info	1,152	618,559	72.2%	80.5%	74.1%	6,944			4,294,974	21,589,547	3.49	
3	*WCEC 01*												
4	Gas		802,654					5,488,017	1,000,000	5,488,017	27,714,631	3.45	5.05
5	Plant Unit Info	1,208	802,654	89.3%	95.5%	89.3%	6,837			5,488,017	27,714,631	3.45	
6	*WCEC 02*												
7	Gas		785,441					5,366,832	1,000,000	5,366,832	26,803,624	3.41	4.99
8	Plant Unit Info	1,202	785,441	87.8%	95.7%	87.8%	6,833			5,366,832	26,803,624	3.41	
9	*WCEC 03*												
10	Gas		223,778					1,558,662	1,000,000	1,558,662	7,873,398	3.52	5.05
11	Plant Unit Info	1,207	223,778	24.9%	31.8%	51.8%	6,965			1,558,662	7,873,398	3.52	
12	**System Totals**												
13	Plant Unit Info	25,900	8,703,360				7,758			67,518,997	257,918,712	2.96	
14													
15													
16													
17													
18													
19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Apr - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		811,352					5,303,570	1,000,000	5,303,570	26,428,645	3.26	4.98
5	Plant Unit Info	1,210	811,352	93.1%	95.8%	93.1%	6,537			5,303,570	26,428,645	3.26	
6	*Desoto Solar*												
7	Solar		5,489					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,489	30.5%		56.3%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,356					3,344	5,830,742	19,498	405,481	29.90	121.26
15	Plant Unit Info	648	1,356	0.3%	95.3%	19.0%	14,379			19,498	405,481	29.90	
16	*Fort Myers 2*												
17	Gas		711,572					5,179,092	1,000,000	5,179,092	26,160,708	3.68	5.05
18	Plant Unit Info	1,380	711,572	71.6%	94.9%	83.6%	7,278			5,179,092	26,160,708	3.68	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		17,652					192,929	1,000,000	192,929	1,010,981	5.73	5.24
22	Plant Unit Info	296	17,652	16.6%	95.5%	95.5%	10,930			192,929	1,010,981	5.73	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		80,535					639,285	1,000,000	639,285	3,330,199	4.14	5.21
30	Plant Unit Info	429	80,535	26.1%	94.0%	91.2%	7,938			639,285	3,330,199	4.14	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		85,048					674,418	1,000,000	674,418	3,519,200	4.14	5.22
34	Plant Unit Info	429	85,048	27.6%	94.6%	94.0%	7,930			674,418	3,519,200	4.14	
35	*Manatee 1*												
36	Heavy Oil		7,260					17,880	6,399,888	114,430	1,684,388	23.20	94.21
37	Gas		20,586					221,609	1,000,000	221,609	1,158,857	5.63	5.23

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	27,846	4.9%	95.3%	49.7%	12,068			336,039	2,843,245	10.21	
2	*Manatee 2*												
3	Heavy Oil		4,812					10,661	6,399,869	68,229	1,004,321	20.87	94.21
4	Gas		11,229					118,162	1,000,000	118,162	622,380	5.54	5.27
5	Plant Unit Info	789	16,041	2.8%	94.0%	63.6%	11,620			186,391	1,626,701	10.14	
6	*Manatee 3*												
7	Gas		611,469					4,254,570	1,000,000	4,254,570	21,537,907	3.52	5.06
8	Plant Unit Info	1,058	611,469	80.3%	94.6%	89.2%	6,958			4,254,570	21,537,907	3.52	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		107,236					828,479	1,000,000	828,479	4,176,635	3.89	5.04
19	Plant Unit Info	438	107,236	34.0%	94.8%	94.2%	7,726			828,479	4,176,635	3.89	
20	*Martin 4*												
21	Gas		95,675					743,649	1,000,000	743,649	3,749,016	3.92	5.04
22	Plant Unit Info	437	95,675	30.4%	94.0%	92.9%	7,773			743,649	3,749,016	3.92	
23	*Martin 8*												
24	Gas		668,423					4,620,965	1,000,000	4,620,965	23,807,061	3.56	5.15
25	Plant Unit Info	1,111	668,423	83.5%	94.9%	83.5%	6,913			4,620,965	23,807,061	3.56	
26	*Martin 8 Solar*												
27	Solar		14,206					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	14,206	26.3%		48.6%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,212	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		24,186					278,144	1,000,000	278,144	1,402,280	5.80	5.04
35	Plant Unit Info	247	24,186	13.6%	17.0%	20.0%	11,500			278,144	1,402,280	5.80	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		44,562					445,167	1,000,000	445,167	2,286,137	5.13	5.14
2	Plant Unit Info	250	44,562	24.7%	85.3%	35.6%	9,990			445,167	2,286,137	5.13	
3	*Sanford 4*												
4	Gas		229,748					1,722,873	1,000,000	1,722,873	8,708,461	3.79	5.05
5	Plant Unit Info	939	229,748	34.0%	75.0%	92.3%	7,499			1,722,873	8,708,461	3.79	
6	*Sanford 5*												
7	Gas		334,183					2,497,655	1,000,000	2,497,655	12,614,202	3.77	5.05
8	Plant Unit Info	947	334,183	49.0%	94.9%	88.4%	7,474			2,497,655	12,614,202	3.77	
9	*Scherer 4*												
10	Coal		120,347					73,952	17,000,068	1,257,189	2,936,970	2.44	39.71
11	Plant Unit Info	641	120,347	26.1%	31.0%	97.4%	10,446			1,257,189	2,936,970	2.44	
12	*St Johns 1O*												
13	Coal		41,111					21,790	22,000,459	479,390	1,659,720	4.04	76.17
14	Plant Unit Info	127	41,111	45.0%	94.0%	45.0%	11,661			479,390	1,659,720	4.04	
15	*St Johns 2O*												
16	Coal		4,999					2,564	22,000,000	56,408	195,297	3.91	76.17
17	Plant Unit Info	127	4,999	5.5%	9.3%	54.7%	11,284			56,408	195,297	3.91	
18	*St Lucie 1*												
19	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,796,000	0.70	0.66
20	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,796,000	0.70	
21	*St Lucie 2*												
22	Nuclear		491,400					5,136,800	1,000,000	5,136,800	3,054,000	0.62	0.59
23	Plant Unit Info	840	491,400	81.3%	81.2%	97.5%	10,453			5,136,800	3,054,000	0.62	
24	*Space Coast*												
25	Solar		1,829					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,829	25.4%		46.9%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		4,990					7,670	6,399,609	49,085	707,139	14.17	92.20
29	Gas		4,029					50,609	1,000,000	50,609	260,952	6.48	5.16
30	Plant Unit Info	379	9,019	3.3%	95.2%	52.8%	11,054			99,694	968,090	10.73	
31	*Turkey Point 3*												
32	Nuclear		226,886					2,539,498	1,000,000	2,539,498	1,737,000	0.77	0.68
33	Plant Unit Info	808	226,886	39.0%	39.0%	97.5%	11,193			2,539,498	1,737,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		574,937					6,435,113	1,000,000	6,435,113	4,126,000	0.72	0.64
36	Plant Unit Info	819	574,937	97.5%	97.5%	97.5%	11,193			6,435,113	4,126,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		537,652					3,758,092	1,000,000	3,758,092	19,126,844	3.56	5.09
2	Plant Unit Info	1,138	537,652	65.6%	89.5%	83.4%	6,990			3,758,092	19,126,844	3.56	
3	*WCEC 01*												
4	Gas		734,618					5,095,693	1,000,000	5,095,693	26,053,570	3.55	5.11
5	Plant Unit Info	1,166	734,618	87.5%	95.5%	87.5%	6,937			5,095,693	26,053,570	3.55	
6	*WCEC 02*												
7	Gas		737,299					5,078,012	1,000,000	5,078,012	25,684,276	3.48	5.06
8	Plant Unit Info	1,159	737,299	88.3%	95.7%	88.3%	6,887			5,078,012	25,684,276	3.48	
9	*WCEC 03*												
10	Gas		721,102					5,001,319	1,000,000	5,001,319	25,398,879	3.52	5.08
11	Plant Unit Info	1,166	721,102	85.9%	95.5%	85.9%	6,936			5,001,319	25,398,879	3.52	
12	**System Totals**												
13	Plant Unit Info	24,933	8,776,442				7,991			70,132,097	259,343,506	2.95	
14													
15													
16													
17													
18													
19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**May - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,558					5,531,199	1,000,000	5,531,199	27,751,726	3.28	5.02
5	Plant Unit Info	1,210	845,558	93.9%	95.8%	93.9%	6,541			5,531,199	27,751,726	3.28	
6	*Desoto Solar*												
7	Solar		5,860					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,860	31.5%		58.2%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		747,450					5,456,209	1,000,000	5,456,209	27,873,255	3.73	5.11
18	Plant Unit Info	1,380	747,450	72.8%	94.9%	89.7%	7,300			5,456,209	27,873,255	3.73	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		16,381					180,183	1,000,000	180,183	937,051	5.72	5.20
22	Plant Unit Info	296	16,381	14.9%	94.0%	95.5%	11,000			180,183	937,051	5.72	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		82,410					654,415	1,000,000	654,415	3,414,247	4.14	5.22
30	Plant Unit Info	429	82,410	25.8%	94.0%	92.4%	7,941			654,415	3,414,247	4.14	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		85,125					676,894	1,000,000	676,894	3,547,335	4.17	5.24
34	Plant Unit Info	429	85,125	26.7%	94.6%	94.5%	7,952			676,894	3,547,335	4.17	
35	*Manatee 1*												
36	Heavy Oil		2,029					7,062	6,399,745	45,195	665,277	32.79	94.21
37	Gas		6,921					75,918	1,000,000	75,918	396,839	5.73	5.23

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	8,950	1.5%	95.3%	40.5%	13,533			121,113	1,062,115	11.87	
2	*Manatee 2*												
3	Heavy Oil		557					1,494	6,401,606	9,564	140,742	25.27	94.21
4	Gas		1,300					13,633	1,000,000	13,633	72,056	5.54	5.29
5	Plant Unit Info	789	1,857	0.3%	94.0%	58.9%	12,492			23,197	212,799	11.46	
6	*Manatee 3*												
7	Gas		525,941					3,671,839	1,000,000	3,671,839	18,777,619	3.57	5.11
8	Plant Unit Info	1,058	525,941	66.8%	80.9%	85.9%	6,981			3,671,839	18,777,619	3.57	
9	*Martin 1*												
10	Heavy Oil		709					1,187	6,397,641	7,594	109,290	15.41	92.07
11	Gas		3,041					46,223	1,000,000	46,223	239,169	7.86	5.17
12	Plant Unit Info	799	3,750	0.6%	29.9%	33.5%	14,350			53,817	348,459	9.29	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		106,285					821,893	1,000,000	821,893	4,192,910	3.94	5.10
19	Plant Unit Info	438	106,285	32.6%	94.8%	94.8%	7,733			821,893	4,192,910	3.94	
20	*Martin 4*												
21	Gas		91,966					715,953	1,000,000	715,953	3,652,390	3.97	5.10
22	Plant Unit Info	437	91,966	28.3%	94.0%	94.0%	7,785			715,953	3,652,390	3.97	
23	*Martin 8*												
24	Gas		731,924					5,071,092	1,000,000	5,071,092	26,194,105	3.58	5.17
25	Plant Unit Info	1,111	731,924	88.5%	94.9%	88.5%	6,928			5,071,092	26,194,105	3.58	
26	*Martin 8 Solar*												
27	Solar		14,070					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	14,070	25.2%		46.6%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	1,212	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		62,706					613,709	1,000,000	613,709	3,170,920	5.06	5.17
35	Plant Unit Info	247	62,706	34.2%	55.4%	43.7%	9,787			613,709	3,170,920	5.06	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		101,364					927,119	1,000,000	927,119	4,818,031	4.75	5.20
2	Plant Unit Info	250	101,364	54.4%	94.8%	69.1%	9,146			927,119	4,818,031	4.75	
3	*Sanford 4*												
4	Gas		278,364					2,096,331	1,000,000	2,096,331	10,704,623	3.85	5.11
5	Plant Unit Info	939	278,364	39.9%	94.7%	95.0%	7,531			2,096,331	10,704,623	3.85	
6	*Sanford 5*												
7	Gas		340,155					2,554,056	1,000,000	2,554,056	13,040,147	3.83	5.11
8	Plant Unit Info	947	340,155	48.3%	94.9%	94.5%	7,509			2,554,056	13,040,147	3.83	
9	*Scherer 4*												
10	Coal		368,558					226,467	16,999,978	3,849,934	8,999,395	2.44	39.74
11	Plant Unit Info	641	368,558	77.3%	93.1%	97.7%	10,446			3,849,934	8,999,395	2.44	
12	*St Johns 1O*												
13	Coal		52,561					26,786	22,000,112	589,295	2,033,173	3.87	75.90
14	Plant Unit Info	127	52,561	55.7%	94.0%	55.7%	11,212			589,295	2,033,173	3.87	
15	*St Johns 2O*												
16	Coal		58,025					29,143	22,000,206	641,152	2,212,079	3.81	75.90
17	Plant Unit Info	127	58,025	61.5%	93.2%	61.5%	11,050			641,152	2,212,079	3.81	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,906					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,906	25.6%		47.3%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		228					372	6,405,914	2,383	34,297	15.04	92.20
29	Gas		3,856					53,030	1,000,000	53,030	273,635	7.10	5.16
30	Plant Unit Info	379	4,084	1.5%	95.2%	33.6%	13,568			55,413	307,932	7.54	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,264,000	0.72	0.64
36	Plant Unit Info	819	594,101	97.5%	97.5%	97.5%	11,193			6,649,613	4,264,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		414,263					2,912,087	1,000,000	2,912,087	14,925,109	3.60	5.13
2	Plant Unit Info	1,138	414,263	48.9%	75.2%	76.1%	7,030			2,912,087	14,925,109	3.60	
3	*WCEC 01*												
4	Gas		801,687					5,553,369	1,000,000	5,553,369	28,510,626	3.56	5.13
5	Plant Unit Info	1,166	801,687	92.4%	95.5%	92.4%	6,927			5,553,369	28,510,626	3.56	
6	*WCEC 02*												
7	Gas		788,246					5,428,082	1,000,000	5,428,082	27,368,758	3.47	5.04
8	Plant Unit Info	1,159	788,246	91.4%	95.7%	92.5%	6,886			5,428,082	27,368,758	3.47	
9	*WCEC 03*												
10	Gas		781,489					5,419,880	1,000,000	5,419,880	27,704,437	3.55	5.11
11	Plant Unit Info	1,166	781,489	90.1%	95.5%	91.0%	6,935			5,419,880	27,704,437	3.55	
12	**System Totals**												
13	Plant Unit Info	24,930	9,822,115				8,217			80,712,474	279,253,240	2.84	
14													
15													
16													
17													
18													
19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jun - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		817,391					5,346,585	1,000,000	5,346,585	26,531,356	3.25	4.96
5	Plant Unit Info	1,210	817,391	93.8%	95.8%	93.8%	6,541			5,346,585	26,531,356	3.25	
6	*Desoto Solar*												
7	Solar		5,136					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,136	28.5%		52.7%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		1,923					5,754	5,829,336	33,542	702,542	36.53	122.10
15	Plant Unit Info	648	1,923	0.4%	95.3%	33.0%	17,443			33,542	702,542	36.53	
16	*Fort Myers 2*												
17	Gas		771,834					5,631,293	1,000,000	5,631,293	28,374,163	3.68	5.04
18	Plant Unit Info	1,380	771,834	77.7%	94.9%	89.5%	7,296			5,631,293	28,374,163	3.68	
19	*Fort Myers 3A B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		28,384					310,711	1,000,000	310,711	1,597,518	5.63	5.14
22	Plant Unit Info	296	28,384	26.7%	74.8%	95.5%	10,947			310,711	1,597,518	5.63	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		88,221					699,644	1,000,000	699,644	3,632,019	4.12	5.19
30	Plant Unit Info	429	88,221	28.6%	94.0%	94.0%	7,931			699,644	3,632,019	4.12	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		101,339					802,256	1,000,000	802,256	4,169,353	4.11	5.20
34	Plant Unit Info	429	101,339	32.8%	94.6%	94.5%	7,917			802,256	4,169,353	4.11	
35	*Manatee 1*												
36	Heavy Oil		14,208					30,254	6,400,079	193,628	2,876,816	20.25	95.09
37	Gas		33,153					346,988	1,000,000	346,988	1,809,289	5.46	5.21

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	47,361	8.3%	95.3%	76.0%	11,415			540,616	4,686,105	9.89	
2	*Manatee 2*												
3	Heavy Oil		7,722					17,636	6,400,034	112,871	1,676,986	21.72	95.09
4	Gas		18,019					188,334	1,000,000	188,334	981,972	5.45	5.21
5	Plant Unit Info	789	25,741	4.5%	94.0%	77.7%	11,701			301,205	2,658,958	10.33	
6	*Manatee 3*												
7	Gas		189,928					1,340,849	1,000,000	1,340,849	6,766,390	3.56	5.05
8	Plant Unit Info	1,058	189,928	24.9%	30.0%	69.1%	7,060			1,340,849	6,766,390	3.56	
9	*Martin 1*												
10	Heavy Oil		18,831					29,505	6,400,000	188,832	2,716,601	14.43	92.07
11	Gas		46,058					556,949	1,000,000	556,949	2,886,723	6.27	5.18
12	Plant Unit Info	799	64,889	11.3%	92.6%	62.0%	11,493			745,781	5,603,323	8.64	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		124,138					956,318	1,000,000	956,318	4,810,769	3.88	5.03
19	Plant Unit Info	438	124,138	39.4%	94.8%	94.8%	7,704			956,318	4,810,769	3.88	
20	*Martin 4*												
21	Gas		103,872					804,350	1,000,000	804,350	4,046,370	3.90	5.03
22	Plant Unit Info	437	103,872	33.1%	90.8%	94.0%	7,744			804,350	4,046,370	3.90	
23	*Martin 8*												
24	Gas		709,102					4,914,366	1,000,000	4,914,366	25,032,195	3.53	5.09
25	Plant Unit Info	1,111	709,102	88.6%	94.9%	88.6%	6,930			4,914,366	25,032,195	3.53	
26	*Martin 8 Solar*												
27	Solar		13,207					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	13,207	24.5%		45.2%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		800,926					5,233,866	1,000,000	5,233,866	25,886,458	3.23	4.95
31	Plant Unit Info	1,212	800,926	91.8%	94.8%	92.9%	6,535			5,233,866	25,886,458	3.23	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		100,020					923,523	1,000,000	923,523	4,742,618	4.74	5.14
35	Plant Unit Info	247	100,020	56.3%	94.2%	74.6%	9,233			923,523	4,742,618	4.74	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		112,066					1,013,534	1,000,000	1,013,534	5,223,407	4.66	5.15
2	Plant Unit Info	250	112,066	62.2%	94.8%	78.6%	9,044			1,013,534	5,223,407	4.66	
3	*Sanford 4*												
4	Gas		341,330					2,553,427	1,000,000	2,553,427	12,854,231	3.77	5.03
5	Plant Unit Info	939	341,330	50.5%	94.7%	94.7%	7,481			2,553,427	12,854,231	3.77	
6	*Sanford 5*												
7	Gas		274,571					2,055,102	1,000,000	2,055,102	10,348,371	3.77	5.04
8	Plant Unit Info	947	274,571	40.3%	70.4%	92.0%	7,485			2,055,102	10,348,371	3.77	
9	*Scherer 4*												
10	Coal		419,242					257,611	17,000,016	4,379,391	10,246,871	2.44	39.78
11	Plant Unit Info	641	419,242	90.9%	93.1%	97.7%	10,446			4,379,391	10,246,871	2.44	
12	*St Johns 1O*												
13	Coal		58,803					29,494	21,999,661	648,858	2,235,442	3.80	75.79
14	Plant Unit Info	127	58,803	64.4%	94.0%	64.4%	11,034			648,858	2,235,442	3.80	
15	*St Johns 2O*												
16	Coal		63,566					31,529	21,999,715	693,629	2,389,681	3.76	75.79
17	Plant Unit Info	127	63,566	69.6%	93.2%	69.6%	10,912			693,629	2,389,681	3.76	
18	*St Lucie 1*												
19	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,796,000	0.70	0.66
20	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,796,000	0.70	
21	*St Lucie 2*												
22	Nuclear		589,677					6,164,182	1,000,000	6,164,182	3,665,000	0.62	0.59
23	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,453			6,164,182	3,665,000	0.62	
24	*Space Coast*												
25	Solar		1,661					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,661	23.1%		42.6%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		3,343					5,051	6,400,119	32,327	465,679	13.93	92.20
29	Gas		15,925					177,871	1,000,000	177,871	921,797	5.79	5.18
30	Plant Unit Info	379	19,268	7.1%	95.2%	67.7%	10,909			210,198	1,387,476	7.20	
31	*Turkey Point 3*												
32	Nuclear		567,218					6,348,776	1,000,000	6,348,776	4,343,000	0.77	0.68
33	Plant Unit Info	808	567,218	97.5%	97.5%	97.5%	11,193			6,348,776	4,343,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		574,937					6,435,113	1,000,000	6,435,113	4,126,000	0.72	0.64
36	Plant Unit Info	819	574,937	97.5%	97.5%	97.5%	11,193			6,435,113	4,126,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		481,400					3,352,103	1,000,000	3,352,103	16,928,752	3.52	5.05
2	Plant Unit Info	1,138	481,400	58.7%	71.4%	69.8%	6,963			3,352,103	16,928,752	3.52	
3	*WCEC 01*												
4	Gas		770,855					5,341,525	1,000,000	5,341,525	27,017,217	3.50	5.06
5	Plant Unit Info	1,166	770,855	91.8%	95.5%	91.8%	6,929			5,341,525	27,017,217	3.50	
6	*WCEC 02*												
7	Gas		419,586					2,901,226	1,000,000	2,901,226	14,813,857	3.53	5.11
8	Plant Unit Info	1,159	419,586	50.3%	56.3%	78.8%	6,914			2,901,226	14,813,857	3.53	
9	*WCEC 03*												
10	Gas		750,431					5,206,507	1,000,000	5,206,507	26,241,381	3.50	5.04
11	Plant Unit Info	1,166	750,431	89.4%	95.5%	90.6%	6,938			5,206,507	26,241,381	3.50	
12	**System Totals**												
13	Plant Unit Info	24,930	10,126,691				8,212			83,160,639	295,856,825	2.92	
14													
15													
16													
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19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jul - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,462					5,530,675	1,000,000	5,530,675	27,582,632	3.26	4.99
5	Plant Unit Info	1,210	845,462	93.9%	95.8%	93.9%	6,542			5,530,675	27,582,632	3.26	
6	*Desoto Solar*												
7	Solar		5,083					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	5,083	27.3%		50.5%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		799					2,308	5,831,456	13,459	281,798	35.27	122.10
15	Plant Unit Info	648	799	0.2%	95.3%	20.6%	16,845			13,459	281,798	35.27	
16	*Fort Myers 2*												
17	Gas		724,996					5,309,295	1,000,000	5,309,295	26,491,263	3.65	4.99
18	Plant Unit Info	1,380	724,996	70.6%	94.9%	91.5%	7,323			5,309,295	26,491,263	3.65	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		34,739					379,837	1,000,000	379,837	1,955,684	5.63	5.15
22	Plant Unit Info	296	34,739	31.6%	95.5%	95.5%	10,934			379,837	1,955,684	5.63	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	840	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		97,084					770,617	1,000,000	770,617	3,973,482	4.09	5.16
30	Plant Unit Info	429	97,084	30.4%	94.0%	94.0%	7,938			770,617	3,973,482	4.09	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		109,852					869,546	1,000,000	869,546	4,483,677	4.08	5.16
34	Plant Unit Info	429	109,852	34.4%	94.6%	94.5%	7,916			869,546	4,483,677	4.08	
35	*Manatee 1*												
36	Heavy Oil		14,248					32,203	6,399,994	206,099	3,081,946	21.63	95.70
37	Gas		33,663					352,504	1,000,000	352,504	1,825,926	5.42	5.18

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	47,911	8.2%	95.3%	73.2%	11,659			558,603	4,907,872	10.24	
2	*Manatee 2*												
3	Heavy Oil		6,662					15,371	6,400,039	98,375	1,471,061	22.08	95.70
4	Gas		15,752					164,781	1,000,000	164,781	852,985	5.42	5.18
5	Plant Unit Info	789	22,414	3.8%	94.0%	72.9%	11,741			263,156	2,324,046	10.37	
6	*Manatee 3*												
7	Gas		442,577					3,117,479	1,000,000	3,117,479	15,583,605	3.52	5.00
8	Plant Unit Info	1,058	442,577	56.2%	73.2%	73.5%	7,044			3,117,479	15,583,605	3.52	
9	*Martin 1*												
10	Heavy Oil		18,813					29,592	6,399,905	189,386	2,724,611	14.48	92.07
11	Gas		46,008					570,308	1,000,000	570,308	2,929,167	6.37	5.14
12	Plant Unit Info	799	64,821	10.9%	92.6%	57.5%	11,720			759,694	5,653,778	8.72	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		127,874					986,053	1,000,000	986,053	4,912,789	3.84	4.98
19	Plant Unit Info	438	127,874	39.2%	94.8%	94.8%	7,711			986,053	4,912,789	3.84	
20	*Martin 4*												
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	437	0	0.0%	0.0%	0.0%	0			0	0	0.00	
23	*Martin 8*												
24	Gas		728,180					5,048,090	1,000,000	5,048,090	25,441,965	3.49	5.04
25	Plant Unit Info	1,111	728,180	88.1%	94.9%	89.0%	6,932			5,048,090	25,441,965	3.49	
26	*Martin 8 Solar*												
27	Solar		12,594					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	12,594	22.6%		36.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		838,794					5,481,564	1,000,000	5,481,564	26,844,363	3.20	4.90
31	Plant Unit Info	1,212	838,794	93.0%	94.8%	93.0%	6,535			5,481,564	26,844,363	3.20	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		110,627					1,020,401	1,000,000	1,020,401	5,222,055	4.72	5.12
35	Plant Unit Info	247	110,627	60.3%	94.2%	74.4%	9,224			1,020,401	5,222,055	4.72	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		121,958					1,102,537	1,000,000	1,102,537	5,654,775	4.64	5.13
2	Plant Unit Info	250	121,958	65.5%	94.8%	78.0%	9,040			1,102,537	5,654,775	4.64	
3	*Sanford 4*												
4	Gas		273,679					2,064,840	1,000,000	2,064,840	10,293,441	3.76	4.99
5	Plant Unit Info	939	273,679	39.2%	79.4%	80.1%	7,545			2,064,840	10,293,441	3.76	
6	*Sanford 5*												
7	Gas		366,541					2,748,388	1,000,000	2,748,388	13,702,323	3.74	4.99
8	Plant Unit Info	947	366,541	52.0%	94.9%	95.6%	7,498			2,748,388	13,702,323	3.74	
9	*Scherer 4*												
10	Coal		434,260					266,839	17,000,026	4,536,270	10,636,666	2.45	39.86
11	Plant Unit Info	641	434,260	91.1%	93.1%	97.7%	10,446			4,536,270	10,636,666	2.45	
12	*St Johns 1O*												
13	Coal		59,279					29,825	22,000,034	656,151	2,261,047	3.81	75.81
14	Plant Unit Info	127	59,279	62.8%	94.0%	62.8%	11,069			656,151	2,261,047	3.81	
15	*St Johns 2O*												
16	Coal		66,282					32,847	22,000,061	722,636	2,490,146	3.76	75.81
17	Plant Unit Info	127	66,282	70.2%	93.2%	70.2%	10,902			722,636	2,490,146	3.76	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,762					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,762	23.7%		43.7%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		14,782					22,419	6,400,018	143,482	2,066,928	13.98	92.20
29	Gas		7,751					99,695	1,000,000	99,695	506,715	6.54	5.08
30	Plant Unit Info	379	22,533	8.0%	95.2%	62.5%	10,792			243,177	2,573,643	11.42	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,264,000	0.72	0.64
36	Plant Unit Info	819	594,101	97.5%	97.5%	97.5%	11,193			6,649,613	4,264,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		671,494					4,676,144	1,000,000	4,676,144	23,374,227	3.48	5.00
2	Plant Unit Info	1,138	671,494	79.3%	94.2%	89.4%	6,964			4,676,144	23,374,227	3.48	
3	*WCEC 01*												
4	Gas		805,649					5,579,551	1,000,000	5,579,551	27,909,050	3.46	5.00
5	Plant Unit Info	1,166	805,649	92.9%	95.5%	92.9%	6,926			5,579,551	27,909,050	3.46	
6	*WCEC 02*												
7	Gas		656,091					4,532,701	1,000,000	4,532,701	22,934,683	3.50	5.06
8	Plant Unit Info	1,159	656,091	76.1%	80.2%	80.5%	6,909			4,532,701	22,934,683	3.50	
9	*WCEC 03*												
10	Gas		765,802					5,310,797	1,000,000	5,310,797	26,515,271	3.46	4.99
11	Plant Unit Info	1,166	765,802	88.3%	95.5%	91.3%	6,935			5,310,797	26,515,271	3.46	
12	**System Totals**												
13	Plant Unit Info	24,930	10,960,315				8,155			89,375,901	321,498,280	2.93	
14													
15													
16													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Aug - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,587					5,531,479	1,000,000	5,531,479	27,597,145	3.26	4.99
5	Plant Unit Info	1,210	845,587	93.9%	95.8%	93.9%	6,542			5,531,479	27,597,145	3.26	
6	*Desoto Solar*												
7	Solar		4,833					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,833	26.0%		48.0%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		285					755	5,778,808	4,363	92,183	32.34	122.10
15	Plant Unit Info	648	285	0.1%	95.3%	22.0%	15,309			4,363	92,183	32.34	
16	*Fort Myers 2*												
17	Gas		641,553					4,721,602	1,000,000	4,721,602	23,564,230	3.67	4.99
18	Plant Unit Info	1,380	641,553	62.5%	94.9%	93.5%	7,360			4,721,602	23,564,230	3.67	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		25,418					279,105	1,000,000	279,105	1,439,909	5.66	5.16
22	Plant Unit Info	296	25,418	23.1%	95.5%	95.5%	10,980			279,105	1,439,909	5.66	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		1,271					29,365	1,000,000	29,365	151,643	11.93	5.16
26	Plant Unit Info	840	1,271	0.2%	95.3%	50.4%	23,100			29,365	151,643	11.93	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		91,041					723,271	1,000,000	723,271	3,731,154	4.10	5.16
30	Plant Unit Info	429	91,041	28.5%	87.9%	94.0%	7,944			723,271	3,731,154	4.10	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		100,934					800,146	1,000,000	800,146	4,132,261	4.09	5.16
34	Plant Unit Info	429	100,934	31.6%	94.6%	94.5%	7,927			800,146	4,132,261	4.09	
35	*Manatee 1*												
36	Heavy Oil		15,090					31,641	6,399,924	202,500	3,028,160	20.07	95.70
37	Gas		21,022					220,148	1,000,000	220,148	1,141,182	5.43	5.18

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	36,112	6.2%	95.3%	72.7%	11,704			422,648	4,169,343	11.55	
2	*Manatee 2*												
3	Heavy Oil		5,010					11,537	6,400,104	73,838	1,104,133	22.04	95.70
4	Gas		11,035					115,267	1,000,000	115,267	597,263	5.41	5.18
5	Plant Unit Info	789	16,045	2.7%	94.0%	75.4%	11,786			189,105	1,701,397	10.60	
6	*Manatee 3*												
7	Gas		637,168					4,426,441	1,000,000	4,426,441	22,099,201	3.47	4.99
8	Plant Unit Info	1,058	637,168	81.0%	90.8%	88.3%	6,947			4,426,441	22,099,201	3.47	
9	*Martin 1*												
10	Heavy Oil		15,212					23,991	6,400,108	153,545	2,208,913	14.52	92.07
11	Gas		39,073					494,115	1,000,000	494,115	2,535,978	6.49	5.13
12	Plant Unit Info	799	54,285	9.1%	92.6%	56.1%	11,931			647,660	4,744,891	8.74	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		119,571					922,730	1,000,000	922,730	4,598,135	3.85	4.98
19	Plant Unit Info	438	119,571	36.7%	94.8%	94.8%	7,717			922,730	4,598,135	3.85	
20	*Martin 4*												
21	Gas		16,833					130,438	1,000,000	130,438	650,050	3.86	4.98
22	Plant Unit Info	437	16,833	5.2%	18.2%	94.0%	7,749			130,438	650,050	3.86	
23	*Martin 8*												
24	Gas		734,652					5,090,174	1,000,000	5,090,174	25,687,416	3.50	5.05
25	Plant Unit Info	1,111	734,652	88.9%	94.9%	88.8%	6,929			5,090,174	25,687,416	3.50	
26	*Martin 8 Solar*												
27	Solar		11,773					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	11,773	21.1%		39.0%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		839,004					5,483,125	1,000,000	5,483,125	26,856,591	3.20	4.90
31	Plant Unit Info	1,212	839,004	93.0%	94.8%	93.0%	6,535			5,483,125	26,856,591	3.20	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		98,737					915,112	1,000,000	915,112	4,699,008	4.76	5.13
35	Plant Unit Info	247	98,737	53.8%	94.2%	71.6%	9,268			915,112	4,699,008	4.76	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		111,520					1,010,849	1,000,000	1,010,849	5,201,991	4.66	5.15
2	Plant Unit Info	250	111,520	59.9%	94.8%	76.8%	9,064			1,010,849	5,201,991	4.66	
3	*Sanford 4*												
4	Gas		243,346					1,843,592	1,000,000	1,843,592	9,191,701	3.78	4.99
5	Plant Unit Info	939	243,346	34.8%	77.9%	78.3%	7,576			1,843,592	9,191,701	3.78	
6	*Sanford 5*												
7	Gas		343,916					2,582,946	1,000,000	2,582,946	12,879,302	3.74	4.99
8	Plant Unit Info	947	343,916	48.8%	94.9%	95.6%	7,510			2,582,946	12,879,302	3.74	
9	*Scherer 4*												
10	Coal		371,687					228,389	17,000,009	3,882,615	9,136,768	2.46	40.01
11	Plant Unit Info	641	371,687	78.0%	93.1%	97.7%	10,446			3,882,615	9,136,768	2.46	
12	*St Johns 1O*												
13	Coal		57,050					28,871	22,000,346	635,172	2,195,369	3.85	76.04
14	Plant Unit Info	127	57,050	60.4%	94.0%	60.4%	11,134			635,172	2,195,369	3.85	
15	*St Johns 2O*												
16	Coal		64,731					32,180	21,999,720	707,951	2,446,987	3.78	76.04
17	Plant Unit Info	127	64,731	68.6%	93.2%	68.6%	10,937			707,951	2,446,987	3.78	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,673					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,673	22.5%		41.5%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		12,415					18,734	6,399,968	119,897	1,727,188	13.91	92.20
29	Gas		5,248					71,217	1,000,000	71,217	363,046	6.92	5.10
30	Plant Unit Info	379	17,663	6.3%	95.2%	67.5%	10,820			191,114	2,090,234	11.83	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		594,101					6,649,613	1,000,000	6,649,613	4,264,000	0.72	0.64
36	Plant Unit Info	819	594,101	97.5%	97.5%	97.5%	11,193			6,649,613	4,264,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		614,881					4,295,744	1,000,000	4,295,744	21,485,477	3.49	5.00
2	Plant Unit Info	1,138	614,881	72.6%	94.2%	90.6%	6,986			4,295,744	21,485,477	3.49	
3	*WCEC 01*												
4	Gas		807,212					5,590,079	1,000,000	5,590,079	27,962,095	3.46	5.00
5	Plant Unit Info	1,166	807,212	93.1%	95.5%	93.0%	6,925			5,590,079	27,962,095	3.46	
6	*WCEC 02*												
7	Gas		800,775					5,513,705	1,000,000	5,513,705	27,953,015	3.49	5.07
8	Plant Unit Info	1,159	800,775	92.8%	95.7%	92.8%	6,885			5,513,705	27,953,015	3.49	
9	*WCEC 03*												
10	Gas		794,169					5,506,221	1,000,000	5,506,221	27,499,829	3.46	4.99
11	Plant Unit Info	1,166	794,169	91.5%	95.5%	91.5%	6,933			5,506,221	27,499,829	3.46	
12	**System Totals**												
13	Plant Unit Info	24,930	11,004,904				8,103			89,170,995	321,451,323	2.92	
14													
15													
16													
17													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Sep - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		818,924					5,357,306	1,000,000	5,357,306	26,855,820	3.28	5.01
5	Plant Unit Info	1,210	818,924	94.0%	95.8%	94.0%	6,542			5,357,306	26,855,820	3.28	
6	*Desoto Solar*												
7	Solar		4,298					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,298	23.9%		44.1%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		585,315					4,306,439	1,000,000	4,306,439	21,641,394	3.70	5.03
18	Plant Unit Info	1,380	585,315	58.9%	94.9%	93.2%	7,357			4,306,439	21,641,394	3.70	
19	*Fort Myers 3A B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		28,102					308,900	1,000,000	308,900	1,596,744	5.68	5.17
22	Plant Unit Info	296	28,102	26.4%	95.5%	95.5%	10,992			308,900	1,596,744	5.68	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		9,161					204,824	1,000,000	204,824	1,065,458	11.63	5.20
26	Plant Unit Info	840	9,161	1.5%	95.3%	43.6%	22,359			204,824	1,065,458	11.63	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	429	0	0.0%	0.0%	0.0%	0			0	0	0.00	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		92,016					733,748	1,000,000	733,748	3,806,161	4.14	5.19
34	Plant Unit Info	429	92,016	29.8%	94.6%	94.5%	7,974			733,748	3,806,161	4.14	
35	*Manatee 1*												
36	Heavy Oil		7,337					17,119	6,399,907	109,560	1,638,351	22.33	95.70
37	Gas		17,534					184,584	1,000,000	184,584	960,485	5.48	5.20

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	24,871	4.4%	95.3%	71.7%	11,827			294,144	2,598,836	10.45	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	789	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		537,569					3,775,556	1,000,000	3,775,556	19,002,763	3.53	5.03
8	Plant Unit Info	1,078	537,569	69.2%	94.6%	92.3%	7,023			3,775,556	19,002,763	3.53	
9	*Martin 1*												
10	Heavy Oil		12,550					19,719	6,400,020	126,202	1,815,579	14.47	92.07
11	Gas		30,973					399,043	1,000,000	399,043	2,060,503	6.65	5.16
12	Plant Unit Info	799	43,523	7.6%	92.6%	61.9%	12,068			525,245	3,876,082	8.91	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		114,173					882,890	1,000,000	882,890	4,431,070	3.88	5.02
19	Plant Unit Info	438	114,173	36.2%	94.8%	94.8%	7,733			882,890	4,431,070	3.88	
20	*Martin 4*												
21	Gas		105,925					823,867	1,000,000	823,867	4,134,894	3.90	5.02
22	Plant Unit Info	437	105,925	33.7%	94.0%	94.0%	7,778			823,867	4,134,894	3.90	
23	*Martin 8*												
24	Gas		690,944					4,792,520	1,000,000	4,792,520	24,320,785	3.52	5.07
25	Plant Unit Info	1,111	690,944	86.4%	94.9%	89.2%	6,936			4,792,520	24,320,785	3.52	
26	*Martin 8 Solar*												
27	Solar		10,217					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	10,217	18.9%		37.8%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		812,599					5,310,953	1,000,000	5,310,953	26,202,099	3.22	4.93
31	Plant Unit Info	1,212	812,599	93.1%	94.8%	93.1%	6,536			5,310,953	26,202,099	3.22	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		99,246					918,921	1,000,000	918,921	4,733,786	4.77	5.15
35	Plant Unit Info	247	99,246	55.9%	94.2%	71.9%	9,259			918,921	4,733,786	4.77	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		114,992					1,040,028	1,000,000	1,040,028	5,372,260	4.67	5.17
2	Plant Unit Info	250	114,992	63.8%	94.8%	78.3%	9,044			1,040,028	5,372,260	4.67	
3	*Sanford 4*												
4	Gas		269,442					2,029,057	1,000,000	2,029,057	10,193,755	3.78	5.02
5	Plant Unit Info	939	269,442	39.9%	94.7%	95.0%	7,531			2,029,057	10,193,755	3.78	
6	*Sanford 5*												
7	Gas		302,285					2,276,333	1,000,000	2,276,333	11,435,200	3.78	5.02
8	Plant Unit Info	947	302,285	44.3%	94.9%	95.6%	7,530			2,276,333	11,435,200	3.78	
9	*Scherer 4*												
10	Coal		357,920					219,930	17,000,023	3,738,815	8,831,719	2.47	40.16
11	Plant Unit Info	641	357,920	77.6%	93.1%	97.7%	10,446			3,738,815	8,831,719	2.47	
12	*St Johns 1O*												
13	Coal		57,613					29,019	22,000,034	638,419	2,210,970	3.84	76.19
14	Plant Unit Info	127	57,613	63.1%	94.0%	63.1%	11,081			638,419	2,210,970	3.84	
15	*St Johns 2O*												
16	Coal		64,481					31,968	21,999,718	703,287	2,435,656	3.78	76.19
17	Plant Unit Info	127	64,481	70.6%	93.2%	70.6%	10,907			703,287	2,435,656	3.78	
18	*St Lucie 1*												
19	Nuclear		688,666					7,272,165	1,000,000	7,272,165	4,796,000	0.70	0.66
20	Plant Unit Info	981	688,666	97.5%	97.5%	97.5%	10,560			7,272,165	4,796,000	0.70	
21	*St Lucie 2*												
22	Nuclear		589,677					6,164,182	1,000,000	6,164,182	3,665,000	0.62	0.59
23	Plant Unit Info	840	589,677	97.5%	97.5%	97.5%	10,453			6,164,182	3,665,000	0.62	
24	*Space Coast*												
25	Solar		1,481					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,481	20.6%		38.0%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		11,354					17,162	6,399,953	109,836	1,582,257	13.94	92.20
29	Gas		5,321					72,049	1,000,000	72,049	368,917	6.93	5.12
30	Plant Unit Info	379	16,675	6.1%	95.2%	67.6%	10,908			181,885	1,951,174	11.70	
31	*Turkey Point 3*												
32	Nuclear		567,218					6,348,776	1,000,000	6,348,776	4,343,000	0.77	0.68
33	Plant Unit Info	808	567,218	97.5%	97.5%	97.5%	11,193			6,348,776	4,343,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		440,785					4,933,613	1,000,000	4,933,613	3,163,000	0.72	0.64
36	Plant Unit Info	819	440,785	74.8%	74.8%	97.5%	11,193			4,933,613	3,163,000	0.72	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		506,126					3,552,099	1,000,000	3,552,099	17,883,977	3.53	5.03
2	Plant Unit Info	1,138	506,126	61.8%	94.2%	91.9%	7,018			3,552,099	17,883,977	3.53	
3	*WCEC 01*												
4	Gas		737,756					5,114,991	1,000,000	5,114,991	25,745,962	3.49	5.03
5	Plant Unit Info	1,166	737,756	87.9%	91.3%	89.4%	6,933			5,114,991	25,745,962	3.49	
6	*WCEC 02*												
7	Gas		775,469					5,340,110	1,000,000	5,340,110	27,214,552	3.51	5.10
8	Plant Unit Info	1,159	775,469	92.9%	95.7%	92.9%	6,886			5,340,110	27,214,552	3.51	
9	*WCEC 03*												
10	Gas		725,483					5,030,523	1,000,000	5,030,523	25,302,263	3.49	5.03
11	Plant Unit Info	1,166	725,483	86.4%	95.5%	91.9%	6,934			5,030,523	25,302,263	3.49	
12	**System Totals**												
13	Plant Unit Info	24,951	10,192,948				8,104			82,599,595	298,810,379	2.93	
14													
15													
16													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Oct - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		845,131					5,529,269	1,000,000	5,529,269	28,254,699	3.34	5.11
5	Plant Unit Info	1,210	845,131	93.9%	95.8%	93.9%	6,542			5,529,269	28,254,699	3.34	
6	*Desoto Solar*												
7	Solar		4,150					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	4,150	22.3%		41.2%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	420	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	648	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		809,794					5,895,869	1,000,000	5,895,869	29,889,848	3.69	5.07
18	Plant Unit Info	1,380	809,794	78.9%	94.9%	88.4%	7,281			5,895,869	29,889,848	3.69	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		19,205					210,084	1,000,000	210,084	1,107,201	5.77	5.27
22	Plant Unit Info	296	19,205	17.5%	95.5%	95.5%	10,939			210,084	1,107,201	5.77	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		2,542					58,669	1,000,000	58,669	309,591	12.18	5.28
26	Plant Unit Info	840	2,542	0.4%	95.3%	50.4%	23,077			58,669	309,591	12.18	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		66,871					531,890	1,000,000	531,890	2,800,667	4.19	5.27
30	Plant Unit Info	429	66,871	21.0%	84.9%	94.0%	7,954			531,890	2,800,667	4.19	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		85,530					679,003	1,000,000	679,003	3,580,140	4.19	5.27
34	Plant Unit Info	429	85,530	26.8%	94.6%	94.5%	7,939			679,003	3,580,140	4.19	
35	*Manatee 1*												
36	Heavy Oil		7,645					15,029	6,400,226	96,189	1,438,331	18.81	95.70
37	Gas		5,197					54,382	1,000,000	54,382	287,369	5.53	5.28

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	789	12,842	2.2%	95.3%	74.0%	11,725			150,571	1,725,700	13.44	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	789	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		647,728					4,520,605	1,000,000	4,520,605	22,940,058	3.54	5.07
8	Plant Unit Info	1,078	647,728	80.7%	94.6%	91.4%	6,979			4,520,605	22,940,058	3.54	
9	*Martin 1*												
10	Heavy Oil		9,724					15,237	6,399,947	97,516	1,402,909	14.43	92.07
11	Gas		18,008					221,630	1,000,000	221,630	1,163,588	6.46	5.25
12	Plant Unit Info	799	27,732	4.7%	92.6%	63.1%	11,508			319,146	2,566,498	9.25	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	802	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		67,674					523,160	1,000,000	523,160	2,646,548	3.91	5.06
19	Plant Unit Info	438	67,674	20.8%	73.4%	94.8%	7,731			523,160	2,646,548	3.91	
20	*Martin 4*												
21	Gas		94,019					729,870	1,000,000	729,870	3,692,255	3.93	5.06
22	Plant Unit Info	437	94,019	29.0%	94.0%	94.0%	7,763			729,870	3,692,255	3.93	
23	*Martin 8*												
24	Gas		727,486					5,042,400	1,000,000	5,042,400	25,906,470	3.56	5.14
25	Plant Unit Info	1,111	727,486	88.0%	94.9%	89.2%	6,931			5,042,400	25,906,470	3.56	
26	*Martin 8 Solar*												
27	Solar		8,981					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	8,981	16.1%		24.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		839,419					5,486,047	1,000,000	5,486,047	27,416,683	3.27	5.00
31	Plant Unit Info	1,212	839,419	93.1%	94.8%	93.1%	6,536			5,486,047	27,416,683	3.27	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		89,122					837,061	1,000,000	837,061	4,372,322	4.91	5.22
35	Plant Unit Info	247	89,122	48.6%	94.2%	60.8%	9,392			837,061	4,372,322	4.91	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		101,684					931,573	1,000,000	931,573	4,879,329	4.80	5.24
2	Plant Unit Info	250	101,684	54.6%	87.1%	66.8%	9,161			931,573	4,879,329	4.80	
3	*Sanford 4*												
4	Gas		268,550					2,015,948	1,000,000	2,015,948	10,226,930	3.81	5.07
5	Plant Unit Info	939	268,550	38.4%	94.7%	95.0%	7,507			2,015,948	10,226,930	3.81	
6	*Sanford 5*												
7	Gas		323,497					2,424,944	1,000,000	2,424,944	12,296,667	3.80	5.07
8	Plant Unit Info	947	323,497	45.9%	94.9%	94.9%	7,496			2,424,944	12,296,667	3.80	
9	*Scherer 4*												
10	Coal		401,199					246,534	16,999,972	4,191,071	9,929,066	2.47	40.27
11	Plant Unit Info	641	401,199	84.2%	93.1%	97.4%	10,446			4,191,071	9,929,066	2.47	
12	*St Johns 1O*												
13	Coal		51,036					26,162	22,000,229	575,570	1,997,908	3.91	76.37
14	Plant Unit Info	127	51,036	54.1%	94.0%	54.1%	11,278			575,570	1,997,908	3.91	
15	*St Johns 2O*												
16	Coal		59,380					29,774	22,000,034	655,029	2,273,744	3.83	76.37
17	Plant Unit Info	127	59,380	62.9%	93.2%	62.9%	11,031			655,029	2,273,744	3.83	
18	*St Lucie 1*												
19	Nuclear		711,622					7,514,567	1,000,000	7,514,567	4,956,000	0.70	0.66
20	Plant Unit Info	981	711,622	97.5%	97.5%	97.5%	10,560			7,514,567	4,956,000	0.70	
21	*St Lucie 2*												
22	Nuclear		609,333					6,369,659	1,000,000	6,369,659	3,787,000	0.62	0.59
23	Plant Unit Info	840	609,333	97.5%	97.5%	97.5%	10,453			6,369,659	3,787,000	0.62	
24	*Space Coast*												
25	Solar		1,427					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,427	19.2%		38.4%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		4,805					7,404	6,400,054	47,386	682,615	14.21	92.20
29	Gas		2,088					32,420	1,000,000	32,420	165,765	7.94	5.11
30	Plant Unit Info	379	6,893	2.4%	95.2%	51.9%	11,578			79,806	848,380	12.31	
31	*Turkey Point 3*												
32	Nuclear		586,125					6,560,405	1,000,000	6,560,405	4,487,000	0.77	0.68
33	Plant Unit Info	808	586,125	97.5%	97.5%	97.5%	11,193			6,560,405	4,487,000	0.77	
34	*Turkey Point 4*												
35	Nuclear		38,329					429,012	1,000,000	429,012	0	0.00	0.00
36	Plant Unit Info	819	38,329	6.3%	6.3%	97.5%	11,193			429,012	0	0.00	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		589,506					4,115,129	1,000,000	4,115,129	20,981,780	3.56	5.10
2	Plant Unit Info	1,138	589,506	69.6%	94.2%	90.8%	6,981			4,115,129	20,981,780	3.56	
3	*WCEC 01*												
4	Gas		42,760					314,071	1,000,000	314,071	1,616,066	3.78	5.15
5	Plant Unit Info	1,166	42,760	4.9%	14.4%	28.6%	7,345			314,071	1,616,066	3.78	
6	*WCEC 02*												
7	Gas		798,279					5,497,511	1,000,000	5,497,511	28,392,877	3.56	5.16
8	Plant Unit Info	1,159	798,279	92.6%	95.7%	92.5%	6,887			5,497,511	28,392,877	3.56	
9	*WCEC 03*												
10	Gas		773,656					5,363,010	1,000,000	5,363,010	27,311,492	3.53	5.09
11	Plant Unit Info	1,166	773,656	89.2%	95.5%	92.0%	6,932			5,363,010	27,311,492	3.53	
12	**System Totals**												
13	Plant Unit Info	24,951	9,711,503				7,985			77,550,947	291,192,917	3.00	
14													
15													
16													
17													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Nov - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		911,005					5,931,462	1,000,000	5,931,462	31,718,652	3.48	5.35
5	Plant Unit Info	1,355	911,005	93.4%	95.8%	93.4%	6,511			5,931,462	31,718,652	3.48	
6	*Desoto Solar*												
7	Solar		3,572					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,572	19.9%		43.3%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		203,575					1,569,592	1,000,000	1,569,592	8,447,771	4.15	5.38
18	Plant Unit Info	1,435	203,575	19.7%	43.3%	56.3%	7,710			1,569,592	8,447,771	4.15	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		1,651					17,744	1,000,000	17,744	96,006	5.82	5.41
22	Plant Unit Info	314	1,651	1.5%	95.5%	95.5%	10,748			17,744	96,006	5.82	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		14,252					113,127	1,000,000	113,127	616,178	4.32	5.45
30	Plant Unit Info	442	14,252	4.5%	94.0%	94.9%	7,938			113,127	616,178	4.32	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		13,866					110,169	1,000,000	110,169	599,910	4.33	5.45
34	Plant Unit Info	442	13,866	4.4%	94.6%	92.4%	7,946			110,169	599,910	4.33	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	795	0	0.0%	63.5%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	795	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		470,830					3,281,875	1,000,000	3,281,875	17,689,286	3.76	5.39
8	Plant Unit Info	1,134	470,830	57.7%	94.6%	90.2%	6,970			3,281,875	17,689,286	3.76	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	805	0	0.0%	92.6%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		60,896					468,039	1,000,000	468,039	2,518,352	4.14	5.38
19	Plant Unit Info	454	60,896	18.6%	94.8%	85.4%	7,686			468,039	2,518,352	4.14	
20	*Martin 4*												
21	Gas		42,652					327,829	1,000,000	327,829	1,763,938	4.14	5.38
22	Plant Unit Info	453	42,652	13.1%	94.0%	85.7%	7,686			327,829	1,763,938	4.14	
23	*Martin 8*												
24	Gas		625,157					4,318,806	1,000,000	4,318,806	23,261,703	3.72	5.39
25	Plant Unit Info	1,147	625,157	75.7%	94.9%	82.5%	6,908			4,318,806	23,261,703	3.72	
26	*Martin 8 Solar*												
27	Solar		6,459					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	6,459	12.0%		19.1%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		899,712					5,847,093	1,000,000	5,847,093	31,071,957	3.45	5.31
31	Plant Unit Info	1,344	899,712	93.0%	94.8%	93.0%	6,499			5,847,093	31,071,957	3.45	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		1,792					17,180	1,000,000	17,180	93,450	5.22	5.44
35	Plant Unit Info	251	1,792	1.0%	94.2%	89.3%	9,588			17,180	93,450	5.22	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		2,623					24,670	1,000,000	24,670	134,399	5.12	5.45
2	Plant Unit Info	255	2,623	1.4%	93.2%	85.8%	9,407			24,670	134,399	5.12	
3	*Sanford 4*												
4	Gas		197,175					1,478,444	1,000,000	1,478,444	7,958,980	4.04	5.38
5	Plant Unit Info	990	197,175	27.7%	94.7%	89.0%	7,498			1,478,444	7,958,980	4.04	
6	*Sanford 5*												
7	Gas		188,283					1,416,033	1,000,000	1,416,033	7,622,646	4.05	5.38
8	Plant Unit Info	994	188,283	26.3%	81.4%	81.0%	7,521			1,416,033	7,622,646	4.05	
9	*Scherer 4*												
10	Coal		339,077					206,720	17,000,029	3,514,246	8,353,111	2.46	40.41
11	Plant Unit Info	646	339,077	73.0%	93.1%	92.3%	10,364			3,514,246	8,353,111	2.46	
12	*St Johns 1O*												
13	Coal		40,833					21,487	22,000,047	472,715	1,645,105	4.03	76.56
14	Plant Unit Info	128	40,833	44.2%	94.0%	44.2%	11,577			472,715	1,645,105	4.03	
15	*St Johns 2O*												
16	Coal		41,887					21,760	21,999,632	478,712	1,666,006	3.98	76.56
17	Plant Unit Info	128	41,887	45.4%	93.2%	45.4%	11,429			478,712	1,666,006	3.98	
18	*St Lucie 1*												
19	Nuclear		704,105					7,272,165	1,000,000	7,272,165	4,796,000	0.68	0.66
20	Plant Unit Info	1,003	704,105	97.5%	97.5%	97.5%	10,328			7,272,165	4,796,000	0.68	
21	*St Lucie 2*												
22	Nuclear		603,721					6,173,813	1,000,000	6,173,813	3,670,000	0.61	0.59
23	Plant Unit Info	860	603,721	97.5%	97.5%	97.5%	10,226			6,173,813	3,670,000	0.61	
24	*Space Coast*												
25	Solar		1,220					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,220	17.0%		37.0%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		377					5,236	1,000,000	5,236	28,325	7.52	5.41
30	Plant Unit Info	380	377	0.1%	95.2%	24.8%	13,908			5,236	28,325	7.52	
31	*Turkey Point 3*												
32	Nuclear		584,765					6,356,602	1,000,000	6,356,602	4,348,000	0.74	0.68
33	Plant Unit Info	833	584,765	97.5%	97.5%	97.5%	10,870			6,356,602	4,348,000	0.74	
34	*Turkey Point 4*												
35	Nuclear		591,786					6,432,893	1,000,000	6,432,893	4,362,000	0.74	0.68
36	Plant Unit Info	843	591,786	97.5%	97.5%	97.5%	10,870			6,432,893	4,362,000	0.74	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		218,992					1,530,441	1,000,000	1,530,441	8,213,244	3.75	5.37
2	Plant Unit Info	1,166	218,992	26.1%	50.2%	93.9%	6,989			1,530,441	8,213,244	3.75	
3	*WCEC 01*												
4	Gas		339,915					2,343,978	1,000,000	2,343,978	12,643,140	3.72	5.39
5	Plant Unit Info	1,208	339,915	39.1%	51.0%	72.0%	6,896			2,343,978	12,643,140	3.72	
6	*WCEC 02*												
7	Gas		731,075					5,006,714	1,000,000	5,006,714	27,015,247	3.70	5.40
8	Plant Unit Info	1,202	731,075	84.5%	95.7%	84.5%	6,848			5,006,714	27,015,247	3.70	
9	*WCEC 03*												
10	Gas		640,191					4,387,510	1,000,000	4,387,510	23,644,681	3.69	5.39
11	Plant Unit Info	1,207	640,191	73.7%	95.5%	84.8%	6,853			4,387,510	23,644,681	3.69	
12	**System Totals**												
13	Plant Unit Info	25,944	8,481,442				8,123			68,897,087	233,978,087	2.76	
14													
15													
16													
17													
18													
19													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Dec - 2014**												
2	*CCEC 3*												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		940,327					6,119,294	1,000,000	6,119,294	33,265,918	3.54	5.44
5	Plant Unit Info	1,355	940,327	93.3%	95.8%	93.3%	6,508			6,119,294	33,265,918	3.54	
6	*Desoto Solar*												
7	Solar		3,244					0	0	0	0	0.00	0.00
8	Plant Unit Info	25	3,244	17.4%		38.1%	0			0	0	0.00	
9	*Everglades 1-12*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	443	0	0.0%	95.3%	0.0%	0			0	0	0.00	
13	*Fort Myers 1-12*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Plant Unit Info	690	0	0.0%	95.3%	0.0%	0			0	0	0.00	
16	*Fort Myers 2*												
17	Gas		330,193					2,419,712	1,000,000	2,419,712	13,275,049	4.02	5.49
18	Plant Unit Info	1,435	330,193	30.9%	94.9%	85.9%	7,328			2,419,712	13,275,049	4.02	
19	*Fort Myers 3A_B*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	314	0	0.0%	95.5%	0.0%	0			0	0	0.00	
23	*Lauderdale 1-24*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	886	0	0.0%	95.3%	0.0%	0			0	0	0.00	
27	*Lauderdale 4*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		26,841					211,007	1,000,000	211,007	1,164,262	4.34	5.52
30	Plant Unit Info	442	26,841	8.2%	94.0%	72.4%	7,861			211,007	1,164,262	4.34	
31	*Lauderdale 5*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		17,903					141,096	1,000,000	141,096	776,648	4.34	5.50
34	Plant Unit Info	442	17,903	5.5%	94.6%	69.9%	7,881			141,096	776,648	4.34	
35	*Manatee 1*												
36	Heavy Oil		0					0	0	0	0	0.00	0.00
37	Gas		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	795	0	0.0%	95.3%	0.0%	0			0	0	0.00	
2	*Manatee 2*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	795	0	0.0%	94.0%	0.0%	0			0	0	0.00	
6	*Manatee 3*												
7	Gas		437,794					3,047,161	1,000,000	3,047,161	16,738,264	3.82	5.49
8	Plant Unit Info	1,134	437,794	51.9%	94.6%	86.7%	6,960			3,047,161	16,738,264	3.82	
9	*Martin 1*												
10	Heavy Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	805	0	0.0%	92.6%	0.0%	0			0	0	0.00	
13	*Martin 2*												
14	Heavy Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	808	0	0.0%	0.0%	0.0%	0			0	0	0.00	
17	*Martin 3*												
18	Gas		29,904					228,711	1,000,000	228,711	1,254,528	4.20	5.49
19	Plant Unit Info	454	29,904	8.9%	94.8%	85.5%	7,648			228,711	1,254,528	4.20	
20	*Martin 4*												
21	Gas		34,439					263,497	1,000,000	263,497	1,445,270	4.20	5.48
22	Plant Unit Info	453	34,439	10.2%	94.0%	80.9%	7,651			263,497	1,445,270	4.20	
23	*Martin 8*												
24	Gas		587,035					4,063,040	1,000,000	4,063,040	22,313,587	3.80	5.49
25	Plant Unit Info	1,147	587,035	68.8%	94.9%	83.9%	6,921			4,063,040	22,313,587	3.80	
26	*Martin 8 Solar*												
27	Solar		5,345					0	0	0	0	0.00	0.00
28	Plant Unit Info	75	5,345	9.6%		19.2%	0			0	0	0.00	
29	*Riviera 5*												
30	Gas		705,500					4,583,073	1,000,000	4,583,073	24,814,195	3.52	5.41
31	Plant Unit Info	1,344	705,500	70.6%	73.4%	92.6%	6,496			4,583,073	24,814,195	3.52	
32	*Putnam 1*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	251	0	0.0%	94.2%	0.0%	0			0	0	0.00	
36	*Putnam 2*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	255	0	0.0%	94.8%	0.0%	0			0	0	0.00	
3	*Sanford 4*												
4	Gas		88,078					662,537	1,000,000	662,537	3,634,641	4.13	5.49
5	Plant Unit Info	990	88,078	12.0%	84.0%	70.6%	7,522			662,537	3,634,641	4.13	
6	*Sanford 5*												
7	Gas		150,326					1,124,159	1,000,000	1,124,159	6,166,927	4.10	5.49
8	Plant Unit Info	994	150,326	20.3%	94.9%	84.5%	7,478			1,124,159	6,166,927	4.10	
9	*Scherer 4*												
10	Coal		347,402					211,770	16,999,972	3,600,084	8,582,953	2.47	40.53
11	Plant Unit Info	646	347,402	72.3%	93.1%	93.1%	10,363			3,600,084	8,582,953	2.47	
12	*St Johns 1O*												
13	Coal		39,261					20,911	22,000,239	460,047	1,604,616	4.09	76.74
14	Plant Unit Info	128	39,261	41.2%	94.0%	41.2%	11,718			460,047	1,604,616	4.09	
15	*St Johns 2O*												
16	Coal		45,235					23,190	22,000,302	510,187	1,779,496	3.93	76.74
17	Plant Unit Info	128	45,235	47.4%	93.2%	47.4%	11,279			510,187	1,779,496	3.93	
18	*St Lucie 1*												
19	Nuclear		727,574					7,514,567	1,000,000	7,514,567	4,956,000	0.68	0.66
20	Plant Unit Info	1,003	727,574	97.5%	97.5%	97.5%	10,328			7,514,567	4,956,000	0.68	
21	*St Lucie 2*												
22	Nuclear		623,845					6,379,606	1,000,000	6,379,606	3,793,000	0.61	0.59
23	Plant Unit Info	860	623,845	97.5%	97.5%	97.5%	10,226			6,379,606	3,793,000	0.61	
24	*Space Coast*												
25	Solar		1,079					0	0	0	0	0.00	0.00
26	Plant Unit Info	10	1,079	14.5%		34.8%	0			0	0	0.00	
27	*Turkey Point 1*												
28	Heavy Oil		0					0	0	0	0	0.00	0.00
29	Gas		0					0	0	0	0	0.00	0.00
30	Plant Unit Info	380	0	0.0%	64.5%	0.0%	0			0	0	0.00	
31	*Turkey Point 3*												
32	Nuclear		604,258					6,568,489	1,000,000	6,568,489	4,493,000	0.74	0.68
33	Plant Unit Info	833	604,258	97.5%	97.5%	97.5%	10,870			6,568,489	4,493,000	0.74	
34	*Turkey Point 4*												
35	Nuclear		611,511					6,647,323	1,000,000	6,647,323	4,508,000	0.74	0.68
36	Plant Unit Info	843	611,511	97.5%	97.5%	97.5%	10,870			6,647,323	4,508,000	0.74	
37	*Turkey Point 5*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		267,184					1,866,389	1,000,000	1,866,389	10,213,096	3.82	5.47
2	Plant Unit Info	1,166	267,184	30.8%	72.9%	87.8%	6,985			1,866,389	10,213,096	3.82	
3	*WCEC 01*												
4	Gas		757,124					5,175,425	1,000,000	5,175,425	28,431,974	3.76	5.49
5	Plant Unit Info	1,208	757,124	84.3%	95.5%	89.4%	6,836			5,175,425	28,431,974	3.76	
6	*WCEC 02*												
7	Gas		763,152					5,211,691	1,000,000	5,211,691	28,585,794	3.75	5.48
8	Plant Unit Info	1,202	763,152	85.3%	95.7%	85.3%	6,829			5,211,691	28,585,794	3.75	
9	*WCEC 03*												
10	Gas		556,890					3,804,507	1,000,000	3,804,507	20,888,316	3.75	5.49
11	Plant Unit Info	1,207	556,890	62.0%	95.5%	86.5%	6,832			3,804,507	20,888,316	3.75	
12	**System Totals**												
13	Plant Unit Info	25,944	8,701,442				8,114			70,601,601	242,685,535	2.79	
14													
15													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Jan - 2014	(3) Feb - 2014	(4) Mar - 2014	(5) Apr - 2014	(6) May - 2014	(7) Jun - 2014	(8) Jul - 2014	(9) Aug - 2014	(10) Sep - 2014	(11) Oct - 2014	(12) Nov - 2014	(13) Dec - 2014	(14) 2014
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	0	0	0	0	0	145,000	145,000	0	0	0	0	0	290,000
4	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	101.7859	100.7759	0.0000	0.0000	0.0000	0.0000	0.0000	101.2809
5	Amount	$0	$0	$0	$0	$0	$14,758,954	$14,612,504	$0	$0	$0	$0	$0	$29,371,458
6	Burned													
7	Units	12,665	2,462	10,334	36,211	10,115	82,446	99,585	85,903	54,000	37,670	0	0	431,391
8	Unit Cost	93.4894	93.4654	93.4659	93.7794	93.8810	93.8321	93.8349	93.9245	93.2627	93.5454	0.0000	0.0000	93.7306
9	Amount	$1,184,043	$230,112	$965,877	$3,395,847	$949,606	$7,736,081	$9,344,546	$8,068,395	$5,036,187	$3,523,855	$0	$0	$40,434,548
10	Ending Inventory													
11	Units	2,754,573	2,752,111	2,741,777	2,705,566	2,690,400	2,735,586	2,803,420	2,717,517	2,663,517	2,625,847	2,625,847	2,625,847	2,625,847
12	Unit Cost	92.9749	92.9745	92.9726	92.9618	93.1329	94.1618	93.7625	93.7573	93.7674	93.7706	93.7706	93.7706	93.7706
13	Amount	$256,106,166	$255,876,055	$254,910,178	$251,514,331	$250,564,725	$257,587,598	$262,855,556	$254,787,161	$249,750,974	$246,227,119	$246,227,119	$246,227,119	$246,227,119
14	**#2 Light Oil (BBLS)**													
15	Purchases													
16	Units	0	0	0	0	0	14,346	0	0	0	0	0	0	14,346
17	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	136.8186	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	136.8186
18	Amount	$0	$0	$0	$0	$0	$1,962,799	$0	$0	$0	$0	$0	$0	$1,962,799
19	Burned													
20	Units	719	134	0	3,344	0	5,753	2,309	755	0	0	0	0	13,014
21	Unit Cost	100.2625	121.2562	0.0000	121.2562	0.0000	122.0963	122.0963	122.0963	0.0000	0.0000	0.0000	0.0000	120.6655
22	Amount	$72,089	$16,248	$0	$405,481	$0	$702,420	$281,920	$92,183	$0	$0	$0	$0	$1,570,341
23	Ending Inventory													
24	Units	1,427,249	1,427,115	1,427,115	1,423,771	1,423,771	1,432,364	1,430,055	1,429,300	1,429,300	1,429,300	1,429,300	1,429,300	1,429,300
25	Unit Cost	118.9547	118.9545	118.9545	118.9491	118.9491	119.1155	119.1106	119.1091	119.1091	119.1091	119.1091	119.1091	119.1091
26	Amount	$169,778,047	$169,761,798	$169,761,798	$169,356,318	$169,356,318	$170,616,697	$170,334,776	$170,242,594	$170,242,594	$170,242,594	$170,242,594	$170,242,594	$170,242,594
27	**Coal - SJRPP (TONS)**													
28	Purchases													
29	Units	28,540	25,850	31,230	28,540	40,940	49,010	49,010	46,320	33,920	44,680	44,680	39,300	462,020
30	Unit Cost	76.9953	77.0269	74.9200	74.8579	74.9874	75.5053	75.8511	76.5436	76.5724	76.6013	76.7741	76.9534	76.1280
31	Amount	$2,197,445	$1,991,145	$2,339,751	$2,136,444	$3,069,983	$3,700,513	$3,717,461	$3,545,498	$2,597,337	$3,422,545	$3,430,266	$3,024,270	$35,172,657
32	Burned													
33	Units	45,856	33,064	22,108	24,354	55,930	61,022	62,672	61,051	60,987	55,936	43,246	44,101	570,327
34	Unit Cost	76.7687	76.8100	76.4406	76.1689	75.9030	75.7931	75.8105	76.0406	76.1904	76.3668	76.5646	76.7372	76.2411
35	Amount	$3,520,307	$2,539,646	$1,689,950	$1,855,018	$4,245,252	$4,625,048	$4,751,193	$4,642,356	$4,646,626	$4,271,652	$3,311,111	$3,384,189	$43,482,348
36	Ending Inventory													
37	Units	135,784	128,570	137,692	141,878	126,889	114,877	101,215	86,484	59,417	48,161	49,594	44,792	44,792
38	Unit Cost	76.7687	76.8100	76.4406	76.1689	75.9043	75.7931	75.8105	76.0406	76.1904	76.3668	76.5628	75.5534	75.5534
39	Amount	$10,423,966	$9,875,464	$10,525,265	$10,806,692	$9,631,422	$8,706,887	$7,673,155	$6,576,297	$4,527,007	$3,677,900	$3,797,055	$3,384,189	$3,384,189
40														

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Jan - 2014	(3) Feb - 2014	(4) Mar - 2014	(5) Apr - 2014	(6) May - 2014	(7) Jun - 2014	(8) Jul - 2014	(9) Aug - 2014	(10) Sep - 2014	(11) Oct - 2014	(12) Nov - 2014	(13) Dec - 2014	(14) 2014
1	**Coal - Scherer (MMBTU)**													
2	Purchases													
3	Units	3,361,141	3,358,193	3,406,575	3,361,439	3,406,575	3,358,193	3,406,575	3,361,439	3,406,575	3,299,389	3,468,625	3,351,400	40,546,118
4	Unit Cost	2.3260	2.3380	2.3423	2.3408	2.3438	2.3496	2.3649	2.3848	2.3937	2.3937	2.4013	2.4071	2.3655
5	Amount	$7,817,921	$7,851,328	$7,979,214	$7,868,353	$7,984,297	$7,890,524	$8,056,276	$8,016,279	$8,154,167	$7,897,599	$8,329,226	$8,067,173	$95,912,355
6	Burned													
7	Units	2,821,520	2,116,078	0	1,257,189	3,849,934	4,379,391	4,536,270	3,882,615	3,738,815	4,191,071	3,514,246	3,600,084	37,887,213
8	Unit Cost	2.3301	2.3323	0.0000	2.3361	2.3375	2.3398	2.3448	2.3532	2.3622	2.3691	2.3769	2.3841	2.3534
9	Amount	$6,574,424	$4,935,418	$0	$2,936,958	$8,999,407	$10,246,862	$10,636,649	$9,136,763	$8,831,708	$9,929,083	$8,353,097	$8,582,967	$89,163,336
10	Ending Inventory													
11	Units	493,355	566,420	766,807	890,587	864,507	804,436	737,984	707,327	687,784	635,331	632,648	618,019	618,019
12	Unit Cost	2.3301	2.3323	2.3349	2.3361	2.3375	2.3398	2.3448	2.3533	2.3622	2.3691	2.3769	2.3841	2.3841
13	Amount	$1,149,564	$1,321,088	$1,790,454	$2,080,536	$2,020,823	$1,882,215	$1,730,428	$1,664,518	$1,624,662	$1,505,163	$1,503,759	$1,473,418	$1,473,418
14	**Gas (MCF)**													
15	Burned													
16	Units	38,202,064	35,717,664	49,002,821	46,704,292	48,473,113	50,657,325	55,715,799	56,296,870	52,454,740	51,014,543	38,195,941	38,921,298	561,356,468
17	Unit Cost	5.3460	5.3053	5.0210	5.0753	5.1073	5.0460	5.0074	5.0095	5.0392	5.1013	5.3707	5.4718	5.1370
18	Amount	$204,229,626	$189,491,935	$246,044,886	$237,037,191	$247,564,987	$255,616,206	$278,990,077	$282,017,622	$264,328,846	$260,238,344	$205,137,865	$212,968,470	$2,883,666,055
19	**Nuclear (Other)**													
20	Burned													
21	Units	27,109,985	24,486,449	17,963,668	21,383,576	27,094,244	26,220,236	27,094,244	27,094,244	24,718,736	20,873,643	26,235,473	27,109,985	297,384,483
22	Unit Cost	0.6466	0.6465	0.5131	0.6413	0.6457	0.6457	0.6457	0.6457	0.6459	0.6338	0.6547	0.6547	0.6383
23	Amount	$17,528,000	$15,831,000	$9,218,000	$13,713,000	$17,494,000	$16,930,000	$17,494,000	$17,494,000	$15,967,000	$13,230,000	$17,176,000	$17,750,000	$189,825,000
24														
25	Note: Totals may not add due to rounding.													

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) SOLD TO	(2) Type & Schedule	(3) Total KWH Sold (000)	(4) KWH from Own Generation (000)	(5) Fuel Cost (cents/KWH)	(6) Total Cost (cents/KWH)	(7) Total $ for Fuel Adjustment (Col(4) * Col(5))	(8) Total Cost ($) (Col(4) * Col(6))	(9) Gain from Off System Sales ($)
1									
2	**January Estimated**								
3	Off System	OS	160,000	160,000	3.357	4.207	$5,370,950	$6,730,950	$993,750
4	St Lucie Reliability Sales		54,189	54,189	0.681	0.681	$368,820	$368,820	$0
5	**Total January Estimated**		214,189	214,189	2.680	3.315	$5,739,770	$7,099,770	$993,750
6									
7	**February Estimated**								
8	Off System	OS	265,000	265,000	3.311	4.161	$8,772,950	$11,025,450	$1,657,500
9	St Lucie Reliability Sales		48,945	48,945	0.681	0.681	$333,129	$333,129	$0
10	**Total February Estimated**		313,945	313,945	2.901	3.618	$9,106,079	$11,358,579	$1,657,500
11									
12	**March Estimated**								
13	Off System	OS	305,000	305,000	3.451	4.337	$10,525,100	$13,227,600	$1,948,750
14	St Lucie Reliability Sales		54,189	54,189	0.681	0.681	$368,820	$368,820	$0
15	**Total March Estimated**		359,189	359,189	3.033	3.785	$10,893,920	$13,596,420	$1,948,750
16									
17	**April Estimated**								
18	Off System	OS	185,000	185,000	4.121	5.042	$7,623,500	$9,328,500	$1,193,750
19	St Lucie Reliability Sales		51,289	51,289	0.696	0.696	$356,923	$356,923	$0
20	**Total April Estimated**		236,289	236,289	3.377	4.099	$7,980,423	$9,685,423	$1,193,750
21									
22	**May Estimated**								
23	Off System	OS	135,000	135,000	3.994	4.964	$5,392,000	$6,702,000	$901,250
24	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
25	**Total May Estimated**		187,999	187,999	3.064	3.761	$5,760,820	$7,070,820	$901,250
26									
27	**June Estimated**								
28	Off System	OS	85,000	85,000	6.443	7.497	$5,476,400	$6,372,650	$650,000
29	St Lucie Reliability Sales		51,289	51,289	0.696	0.696	$356,923	$356,923	$0
30	**Total June Estimated**		136,289	136,289	4.280	4.938	$5,833,323	$6,729,573	$650,000
31									
32	**6 Month Period**								
33	Off System	OS	1,135,000	1,135,000	3.803	4.704	$43,160,900	$53,387,150	$7,345,000
34	St Lucie Reliability Sales		312,901	312,901	0.688	0.688	$2,153,437	$2,153,437	$0
35	**Total 6 Month Period**		1,447,901	1,447,901	3.130	3.836	$45,314,337	$55,540,587	$7,345,000
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	SOLD TO	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total $ for Fuel Adjustment (Col(4) * Col(5))	Total Cost ($) (Col(4) * Col(6))	Gain from Off System Sales ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1									
2	**July Estimated**								
3	Off System	OS	95,000	95,000	6.561	7.722	$6,233,200	$7,335,700	$823,750
4	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
5	**Total July Estimated**		147,999	147,999	4.461	5.206	$6,602,020	$7,704,520	$823,750
6									
7	**August Estimated**								
8	Off System	OS	70,000	70,000	5.256	6.324	$3,679,100	$4,426,600	$565,000
9	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
10	**Total August Estimated**		122,999	122,999	3.291	3.899	$4,047,920	$4,795,420	$565,000
11									
12	**September Estimated**								
13	Off System	OS	25,000	25,000	5.521	6.601	$1,380,150	$1,650,150	$203,750
14	St Lucie Reliability Sales		51,289	51,289	0.696	0.696	$356,923	$356,923	$0
15	**Total September Estimated**		76,289	76,289	2.277	2.631	$1,737,073	$2,007,073	$203,750
16									
17	**October Estimated**								
18	Off System	OS	40,000	40,000	4.005	4.967	$1,601,800	$1,986,800	$290,000
19	St Lucie Reliability Sales		52,999	52,999	0.696	0.696	$368,820	$368,820	$0
20	**Total October Estimated**		92,999	92,999	2.119	2.533	$1,970,620	$2,355,620	$290,000
21									
22	**November Estimated**								
23	Off System	OS	100,000	100,000	3.123	3.986	$3,123,000	$3,985,500	$637,500
24	St Lucie Reliability Sales		52,441	52,441	0.681	0.681	$356,923	$356,923	$0
25	**Total November Estimated**		152,441	152,441	2.283	2.849	$3,479,923	$4,342,423	$637,500
26									
27	**December Estimated**								
28	Off System	OS	190,000	190,000	3.246	4.096	$6,167,600	$7,782,600	$1,215,000
29	St Lucie Reliability Sales		54,189	54,189	0.681	0.681	$368,820	$368,820	$0
30	**Total December Estimated**		244,189	244,189	2.677	3.338	$6,536,420	$8,151,420	$1,215,000
31									
32	**12 Month Period**								
33	Off System	OS	1,655,000	1,655,000	3.948	4.867	$65,345,750	$80,554,500	$11,080,000
34	St Lucie Reliability Sales		629,817	629,817	0.689	0.689	$4,342,565	$4,342,565	$0
35	**Total 12 Month Period**		2,284,817	2,284,817	3.050	3.716	$69,688,315	$84,897,065	$11,080,000
36									
37									
38	Note: Totals may not add due to rounding.								

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**January Estimated**					
3	UPS		78,701	78,701	4.053	$3,189,917
4	SJRPP		139,422	139,422	3.974	$5,541,000
5	St Lucie Reliability		46,464	46,464	0.649	$301,580
6	**Total January Estimated**		264,587	264,587	3.414	$9,032,496
7						
8	**February Estimated**					
9	UPS		90,469	90,469	4.106	$3,714,827
10	SJRPP		114,571	114,571	4.047	$4,637,000
11	St Lucie Reliability		41,967	41,967	0.649	$272,395
12	**Total February Estimated**		247,007	247,007	3.491	$8,624,221
13						
14	**March Estimated**					
15	UPS		176,756	176,756	3.867	$6,835,040
16	SJRPP		65,075	65,075	3.939	$2,563,000
17	St Lucie Reliability		2,998	2,998	0.000	$0
18	**Total March Estimated**		244,829	244,829	3.839	$9,398,040
19						
20	**April Estimated**					
21	UPS		148,871	148,871	3.928	$5,848,164
22	SJRPP		85,847	85,847	3.966	$3,405,000
23	St Lucie Reliability		36,600	36,600	0.625	$228,626
24	**Total April Estimated**		271,318	271,318	3.495	$9,481,790
25						
26	**May Estimated**					
27	UPS		180,259	180,259	3.862	$6,961,940
28	SJRPP		165,532	165,532	3.793	$6,279,000
29	St Lucie Reliability		45,379	45,379	0.625	$283,481
30	**Total May Estimated**		391,170	391,170	3.457	$13,524,421
31						
32	**June Estimated**					
33	UPS		212,863	212,863	3.868	$8,232,812
34	SJRPP		182,976	182,976	3.766	$6,890,000
35	St Lucie Reliability		43,920	43,920	0.626	$274,814
36	**Total June Estimated**		439,759	439,759	3.501	$15,397,625
37						
38	**6 Month Period**					
39	UPS		887,919	887,919	3.917	$34,782,699
40	SJRPP		753,423	753,423	3.891	$29,315,000
41	St Lucie Reliability		217,327	217,327	0.626	$1,360,894
42	**Total 6 Month Period**		1,858,669	1,858,669	3.522	$65,458,594
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FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) KWH For Firm (000)	(5) Fuel Cost (cents/KWH)	(6) Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**July Estimated**					
3	UPS		224,517	224,517	3.888	$8,729,299
4	SJRPP		188,550	188,550	3.784	$7,135,000
5	St Lucie Reliability		45,379	45,379	0.625	$283,481
6	**Total July Estimated**		458,446	458,446	3.522	$16,147,779
7						
8	**August Estimated**					
9	UPS		218,279	218,279	3.902	$8,518,106
10	SJRPP		182,339	182,339	3.837	$6,997,000
11	St Lucie Reliability		45,379	45,379	0.625	$283,481
12	**Total August Estimated**		445,997	445,997	3.542	$15,798,587
13						
14	**September Estimated**					
15	UPS		226,436	226,436	3.944	$8,931,460
16	SJRPP		182,651	182,651	3.824	$6,985,000
17	St Lucie Reliability		43,920	43,920	0.626	$274,814
18	**Total September Estimated**		453,007	453,007	3.574	$16,191,274
19						
20	**October Estimated**					
21	UPS		172,291	172,291	3.950	$6,804,871
22	SJRPP		165,346	165,346	3.880	$6,416,000
23	St Lucie Reliability		45,379	45,379	0.625	$283,481
24	**Total October Estimated**		383,016	383,016	3.526	$13,504,351
25						
26	**November Estimated**					
27	UPS		76,363	76,363	4.138	$3,159,621
28	SJRPP		132,578	132,578	3.988	$5,287,000
29	St Lucie Reliability		44,965	44,965	0.612	$275,201
30	**Total November Estimated**		253,906	253,906	3.435	$8,721,822
31						
32	**December Estimated**					
33	UPS		69,811	69,811	4.154	$2,899,715
34	SJRPP		132,873	132,873	4.002	$5,317,000
35	St Lucie Reliability		46,464	46,464	0.612	$284,374
36	**Total December Estimated**		249,148	249,148	3.412	$8,501,088
37						
38	**12 Month Period**					
39	UPS		1,875,616	1,875,616	3.936	$73,825,771
40	SJRPP		1,737,760	1,737,760	3.882	$67,452,000
41	St Lucie Reliability		488,814	488,814	0.623	$3,045,725
42	**Total 12 Month Period**		4,102,190	4,102,190	3.518	$144,323,495
43						
44						
45	Note: Totals may not add due to rounding.					
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) KWH For Firm (000)	(5) Fuel Cost (cents/KWH)	(6) Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**January Estimated**					
3	Qualifying Facilities		241,864	241,864	4.112	$9,945,865
4	**Total January Estimated**		241,864	241,864	4.112	$9,945,865
5						
6	**February Estimated**					
7	Qualifying Facilities		219,252	219,252	4.051	$8,880,867
8	**Total February Estimated**		219,252	219,252	4.051	$8,880,867
9						
10	**March Estimated**					
11	Qualifying Facilities		246,666	246,666	4.180	$10,309,866
12	**Total March Estimated**		246,666	246,666	4.180	$10,309,866
13						
14	**April Estimated**					
15	Qualifying Facilities		135,599	135,599	4.423	$5,997,865
16	**Total April Estimated**		135,599	135,599	4.423	$5,997,865
17						
18	**May Estimated**					
19	Qualifying Facilities		263,130	263,130	4.123	$10,849,865
20	**Total May Estimated**		263,130	263,130	4.123	$10,849,865
21						
22	**June Estimated**					
23	Qualifying Facilities		297,827	297,827	4.451	$13,256,860
24	**Total June Estimated**		297,827	297,827	4.451	$13,256,860
25						
26	**6 Month Period**					
27	Qualifying Facilities		1,404,338	1,404,338	4.218	$59,241,188
28	**Total 6 Month Period**		1,404,338	1,404,338	4.218	$59,241,188
29						
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35						
36						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) KWH For Firm (000)	(5) Fuel Cost (cents/KWH)	(6) Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**July Estimated**					
3	Qualifying Facilities		317,110	317,110	4.420	$14,016,861
4	**Total July Estimated**		317,110	317,110	4.420	$14,016,861
5						
6	**August Estimated**					
7	Qualifying Facilities		307,485	307,485	4.471	$13,746,860
8	**Total August Estimated**		307,485	307,485	4.471	$13,746,860
9						
10	**September Estimated**					
11	Qualifying Facilities		303,307	303,307	4.541	$13,771,859
12	**Total September Estimated**		303,307	303,307	4.541	$13,771,859
13						
14	**October Estimated**					
15	Qualifying Facilities		236,812	236,812	4.155	$9,839,862
16	**Total October Estimated**		236,812	236,812	4.155	$9,839,862
17						
18	**November Estimated**					
19	Qualifying Facilities		156,967	156,967	4.445	$6,976,866
20	**Total November Estimated**		156,967	156,967	4.445	$6,976,866
21						
22	**December Estimated**					
23	Qualifying Facilities		214,386	214,386	4.186	$8,973,866
24	**Total December Estimated**		214,386	214,386	4.186	$8,973,866
25						
26	**12 Month Period**					
27	Qualifying Facilities		2,940,405	2,940,405	4.304	$126,567,361
28	**Total 12 Month Period**		2,940,405	2,940,405	4.304	$126,567,361
29						
30						
31	Note: Totals may not add due to rounding.					
32						
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) Transaction Cost (cents/KWH)	(5) Total $ for Fuel Adj (Col(3) * Col(4))	(6) Cost if Generated (cents/KWH)	(7) Cost if Generated ($) (Col(3) * Col(6))	(8) Fuel Savings ($) (Col(7) - Col(5))
1								
2	**January Estimated**							
3	Economy	OS	7,100	2.781	$197,461	3.578	$254,061	$56,600
4	Total January Estimated		7,100	2.781	$197,461	3.578	$254,061	$56,600
5								
6	**February Estimated**							
7	Economy	OS	3,100	2.751	$85,278	3.544	$109,878	$24,600
8	Total February Estimated		3,100	2.751	$85,278	3.544	$109,878	$24,600
9								
10	**March Estimated**							
11	Economy	OS	3,100	2.781	$86,206	3.671	$113,806	$27,600
12	Total March Estimated		3,100	2.781	$86,206	3.671	$113,806	$27,600
13								
14	**April Estimated**							
15	Economy	OS	17,100	3.038	$519,450	4.433	$758,050	$238,600
16	Total April Estimated		17,100	3.038	$519,450	4.433	$758,050	$238,600
17								
18	**May Estimated**							
19	Economy	OS	5,100	3.055	$155,794	4.145	$211,394	$55,600
20	Total May Estimated		5,100	3.055	$155,794	4.145	$211,394	$55,600
21								
22	**June Estimated**							
23	Economy	OS	55,100	5.455	$3,005,537	7.452	$4,106,137	$1,100,600
24	Total June Estimated		55,100	5.455	$3,005,537	7.452	$4,106,137	$1,100,600
25								
26	**6 Month Period**							
27	Economy	OS	90,600	4.470	$4,049,726	6.129	$5,553,326	$1,503,600
28	Total 6 Month Period		90,600	4.470	$4,049,726	6.129	$5,553,326	$1,503,600
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) Transaction Cost (cents/KWH)	(5) Total $ for Fuel Adj (Col(3) * Col(4))	(6) Cost if Generated (cents/KWH)	(7) Cost if Generated ($) (Col(3) * Col(6))	(8) Fuel Savings ($) (Col(7) - Col(5))
1								
2	**July Estimated**							
3	Economy	OS	70,200	5.448	$3,824,412	7.444	$5,225,612	$1,401,200
4	Total July Estimated		70,200	5.448	$3,824,412	7.444	$5,225,612	$1,401,200
5								
6	**August Estimated**							
7	Economy	OS	60,200	4.897	$2,947,914	6.892	$4,149,114	$1,201,200
8	Total August Estimated		60,200	4.897	$2,947,914	6.892	$4,149,114	$1,201,200
9								
10	**September Estimated**							
11	Economy	OS	35,200	5.130	$1,805,718	7.122	$2,506,918	$701,200
12	Total September Estimated		35,200	5.130	$1,805,718	7.122	$2,506,918	$701,200
13								
14	**October Estimated**							
15	Economy	OS	20,100	3.559	$715,344	5.054	$1,015,944	$300,600
16	Total October Estimated		20,100	3.559	$715,344	5.054	$1,015,944	$300,600
17								
18	**November Estimated**							
19	Economy	OS	1,100	2.691	$29,606	3.382	$37,206	$7,600
20	Total November Estimated		1,100	2.691	$29,606	3.382	$37,206	$7,600
21								
22	**December Estimated**							
23	Economy	OS	1,100	2.802	$30,818	3.493	$38,418	$7,600
24	Total December Estimated		1,100	2.802	$30,818	3.493	$38,418	$7,600
25								
26	**12 Month Period**							
27	Economy	OS	278,500	4.813	$13,403,538	6.652	$18,526,538	$5,123,000
28	Total 12 Month Period		278,500	4.813	$13,403,538	6.652	$18,526,538	$5,123,000
29								
30								
31	Note: Totals may not add due to rounding.							
32								
33								
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COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	SEPT 13	PROPOSED [1], [2] JAN 14 - MAY 14	DIFFERENCE $	%
BASE	$51.33	$52.48	$1.15	2.24%
FUEL	$26.33	$30.67	$4.34	16.48%
CONSERVATION [2]	$2.33	$3.37	$1.04	44.64%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%
STORM RESTORATION SURCHARGE	$1.07	$1.07	$0.00	0.00%
SUBTOTAL	$92.73	$97.75	$5.02	5.41%
GROSS RECEIPTS TAX	$2.38	$2.51	$0.13	5.46%
TOTAL	**$95.11**	**$100.26**	$5.15	5.41%

Note: [1] Base rate changes are based on estimated EPU increase.
[2] Based on estimates of the Conservation factor to be filed on September 10, 2013.

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL [1]	ACTUAL [1]	ACTUAL/ESTIMATED [1]	PROJECTED			
		JAN - DEC 2011-2011 (COLUMN 1)	JAN - DEC 2012-2012 (COLUMN 2)	JAN-DEC 2013-2013 (COLUMN 3)	JAN-DEC 2014-2014 (COLUMN 4)	(COLUMN 2) (COLUMN 1)	(COLUMN 3) (COLUMN 2)	(COLUMN 4) (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	93,949,810	61,871,530	62,546,825	40,434,454	(34.1)	1.1	(35.4)
2	LIGHT OIL	37,159,006	8,584,943	9,997,129	1,570,341	(76.9)	16.4	(84.3)
3	COAL	163,820,388	142,583,650	155,340,329	132,645,707	(13.0)	8.9	(14.6)
4	GAS	3,289,409,517	2,999,049,429	2,653,084,633	2,883,666,055	(8.8)	(11.5)	8.7
5	NUCLEAR	146,597,226	106,563,067	183,254,616	189,825,000	(27.3)	72.0	3.6
6	TOTAL ($)	3,730,935,950	3,318,652,620	3,064,223,534	3,248,141,556	(11.1)	(7.7)	6.0
	SYSTEM NET GENERATION							
7	HEAVY OIL	630,196	377,642	392,709	232,756	(40.1)	4.0	(40.7)
8	LIGHT OIL	232,917	54,367	49,192	4,989	(76.7)	(9.5)	(89.9)
9	COAL	5,634,006	4,745,211	5,640,049	4,755,642	(15.8)	18.9	(15.7)
10	GAS	74,277,900	80,593,957	75,136,502	79,726,968	8.5	(6.8)	6.1
11	NUCLEAR	21,510,395	16,915,746	25,480,181	27,766,399	(21.4)	50.6	9.0
12	SOLAR	70,687	70,534	106,585	190,625	(0.2)	51	78.8
13	TOTAL (MWH)	102,356,101	102,757,457	106,805,219	112,677,379	0.4	3.9	5.5
	UNITS OF FUEL BURNED							
14	HEAVY OIL (Bbl)	1,140,665	701,587	667,611	431,390	(38.5)	(4.8)	(35.4)
15	LIGHT OIL (Bbl)	331,653	72,767	84,377	13,014	(78.1)	16.0	(84.6)
16	COAL (TON)	637,734	578,328	592,055	2,798,987	(9.3)	2.4	372.8
17	GAS (MCF)	555,912,325	595,396,296	538,831,472	561,356,468	7.1	(9.5)	4.2
18	NUCLEAR (MMBTU)	241,129,910	188,199,021	271,163,896	297,384,483	(22.0)	44.1	9.7
	BTU'S BURNED (MMBTU)							
19	HEAVY OIL	7,268,455	4,479,894	4,269,282	2,760,893	(38.4)	(4.7)	(35.3)
20	LIGHT OIL	1,909,037	418,441	488,982	75,793	(78.1)	16.9	(84.5)
21	COAL	57,605,124	49,417,119	58,421,837	50,434,432	(14.2)	18.2	(13.7)
22	GAS	564,067,472	603,981,012	543,369,637	561,356,468	7.1	(10.0)	3.3
23	NUCLEAR	241,129,910	188,199,021	271,163,896	297,384,483	(22.0)	44.1	9.7
24	TOTAL (MMBTU)	871,979,998	846,495,487	877,713,634	912,012,069	(2.9)	3.7	3.9
	GENERATION MIX (%MWH)							
25	HEAVY OIL	0.62	0.37	0.37	0.21	-	-	-
26	LIGHT OIL	0.23	0.05	0.05	0.00	-	-	-
27	COAL	5.50	4.62	5.28	4.22			
28	GAS	72.57	78.43	70.35	70.76	-	-	-
29	NUCLEAR	21.02	16.46	23.86	24.64	-	-	-
30	SOLAR	0.07	0.07	0.10	0.17			
31	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
32	HEAVY OIL ($/Bbl)	82.3641	88.1880	93.6875	93.7306	7.1	6.2	0.0
33	LIGHT OIL ($/Bbl)	112.0418	117.9785	118.4817	120.6655	5.3	0.4	1.8
34	COAL ($/TON)	92.3945	82.6550	76.8296	47.3906	(10.5)	(7.0)	(38.3)
35	GAS ($/MCF)	5.9171	5.0371	4.9238	5.1370	(14.9)	(2.2)	4.3
36	NUCLEAR ($/MMBTU)	0.6080	0.5662	0.6758	0.6383	(6.9)	19.4	(5.5)
	FUEL COST PER MMBTU ($/MMBTU)							
37	HEAVY OIL	12.9257	13.8109	14.6504	14.6454	6.8	6.1	(0.0)
38	LIGHT OIL	19.4648	20.5165	20.4448	20.7188	5.4	(0.3)	1.3
39	COAL	2.8439	2.8853	2.6589	2.6301	1.5	(7.8)	(1.1)
40	GAS	5.8316	4.9655	4.8827	5.1370	(14.9)	(1.7)	5.2
41	NUCLEAR	0.6080	0.5662	0.6758	0.6383	(6.9)	19.4	(5.5)
42	TOTAL ($/MMBTU)	4.2787	3.9205	3.4911	3.5615	(8.4)	(11.0)	2.0
	BTU BURNED PER KWH (BTU/KWH)							
43	HEAVY OIL	11,534	11,863	10,871	11,862	2.9	(8.4)	9.1
44	LIGHT OIL	8,196	7,697	9,940	15,192	(6.1)	29.2	52.8
45	COAL	10,225	10,414	10,358	10,605	1.9	(0.5)	2.4
46	GAS	7,594	7,494	7,232	7,041	(1.3)	(3.5)	(2.6)
47	NUCLEAR	11,210	11,126	10,642	10,710	(0.8)	(4.3)	0.6
48	TOTAL (BTU/KWH)	8,519	8,238	8,218	8,094	(3.3)	(0.2)	(1.5)
	GENERATED FUEL COST PER KWH (c/KWH)							
49	HEAVY OIL	14.9080	16.3836	15.9270	17.3720	9.9	(2.8)	9.1
50	LIGHT OIL	15.9538	15.7907	20.3226	31.4761	(1.0)	28.7	54.9
51	COAL	2.9077	3.0048	2.7542	2.7892	3.3	(8.3)	1.3
52	GAS	4.4285	3.7212	3.5310	3.6169	(16.0)	(5.1)	2.4
53	NUCLEAR	0.6815	0.6300	0.7192	0.6837	(7.6)	14.2	(4.9)
54	TOTAL (c/KWH)	3.6451	3.2296	2.8690	2.8827	(11.4)	(11.2)	0.5

Note: [1] Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next two periods are as follows. In addition, As-Available Energy cost payments will include .0074¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2014 – December 31, 2014	4.27	3.87	3.98
January 1, 2015 – December 31, 2015	4.10	3.87	3.93

A MW block size ranging from 70 MW to 77 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0104
Secondary Voltage Delivery	1.0420

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)						Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Solar	Nuclear	Oil	Gas	Coal
2013	24.0	0.2	66.1	4.3	5.2	0.2	.73	41.11	3.71	2.69
2014	23.4	0.2	66.3	4.4	5.6	0.2	.75	39.71	4.23	2.71
2015	23.1	0.3	65.4	4.9	6.2	0.1	.76	38.35	4.43	2.79
2016	23.2	0.4	66.9	4.4	5.0	0.2	.78	38.58	4.68	2.87
2017	22.7	0.1	68.0	4.9	4.1	0.1	.80	38.55	5.03	2.80
2018	22.2	0.2	68.9	4.8	3.7	0.1	.82	41.31	5.85	2.97
2019	22.5	0.1	66.9	5.2	5.1	0.1	.84	42.33	6.40	3.74
2020	21.9	0.2	67.0	5.3	5.4	0.1	.86	43.42	6.94	3.88
2021	21.6	0.2	67.1	5.5	5.5	0.1	.88	45.46	7.33	3.97
2022	25.6	0.1	63.2	5.4	5.6	0.1	.90	47.80	7.65	4.06

NOTE: - Amounts may not add to 100% due to rounding.
- The Company's forecasts are for illustrative purposes, and are subject to frequent revisions.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.137%
Distribution Equipment	0.203%
Transmission Equipment	0.133%

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III
FUEL COST RECOVERY
2014 E-SCHEDULES

INCLUDING RIVIERA BEACH MODERNIZATION PROJECT FUEL SAVINGS BEGINNING IN JUNE 1, 2014

TJK-6
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-7
AUGUST 30, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 15
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-6

APPENDIX III
FUEL COST RECOVERY
2014 E SCHEDULES
TABLE OF CONTENTS

PAGE(S)	SCHEDULES	SPONSOR
1-2	Schedule E1 Fuel & Purchased Power Cost Recovery Clause Calculation	T.J. Keith
3-4	Schedule E1-E Factors by Rate Group	T.J. Keith
5	Schedule E2 Monthly Summary of Fuel & Purchased Power Cost Recovery Clause Calculation	T.J. Keith / G.Yupp
6	Residential Inverted Rate Calculation	T.J. Keith
7	Schedule E10 Residential Bill Comparison	T.J. Keith

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,248,141,556	112,677,379	2.8827
2	Riviera Beach Energy Center (RBEC) Savings	$82,000,000	112,677,379	0.0728
3	Nuclear Fuel Disposal Costs (E2)	$26,064,319	27,766,399	0.0939
4	TOTAL COST OF GENERATED POWER	$3,356,205,875	112,677,379	2.9786
5	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$144,323,495	4,102,190	3.5182
6	Energy Cost of Economy Purchases (E9)	$13,403,538	278,500	4.8128
7	Payments to Qualifying Facilities (E8)	$126,567,361	2,940,405	4.3044
8	TOTAL COST OF PURCHASED POWER	$284,294,395	7,321,095	3.8832
9	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)		119,998,473	
10	Fuel Cost of Economy Sales (E6)	($65,345,750)	(1,655,000)	3.9484
11	Gain from Off-System Sales (E6)	($11,080,000)	N/A	N/A
12	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,342,565)	(629,817)	0.6895
13	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,768,315)	(2,284,817)	3.5350
14	Incremental Personnel, Software, and Hardware Costs	$389,472	N/A	N/A
15	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,722,910	N/A	N/A
16	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,112,382	N/A	N/A
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 4 + 8 + 13 + 16)	$3,561,844,337	117,713,657	3.0259
18	Net Unbilled Sales [1]	($32,030,707)	(1,058,567)	(0.0289)
19	Company Use [1]	$10,685,533	353,141	0.0096
20	T & D Losses [1]	$231,519,882	7,651,388	0.2090
21	SYSTEM MWH SALES	$3,561,844,337	110,767,695	3.2156
22	Wholesale MWH Sales	$158,351,051	4,924,470	3.2156
23	Jurisdictional MWH Sales	$3,403,493,286	105,843,225	3.2156
24	Jurisdictional Loss Multiplier	$5,751,904		1.00169
25	Jurisdictional MWH Sales Adjusted for Line Losses	$3,409,245,189	105,843,225	3.2210
26	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$147,765,613	105,843,225	0.1396
27	TOTAL JURISDICTIONAL FUEL COST	$3,557,010,803	105,843,225	3.3606
28	Revenue Tax Factor	$2,561,048		1.00072
29	Fuel Factor Adjusted for Taxes	$3,559,571,851	105,843,225	3.3630
30	GPIF [2]	$20,679,970	105,843,225	0.0195
31	Jurisdictionalized RBEC Savings	($78,543,407)	65,556,788	(0.1198)
32	Fuel Factor including GPIF (Line 29 + 30 + 31)	$3,501,708,414	105,843,225	3.2627
33	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.263
34				
35	[1] For Informational Purposes Only			
36	[2] Calculation Based on Jurisdictional KWH Sales			
37				
38	Note: Totals may not add due to rounding.			

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

Line No.	CALCULATION OF JURISDICTIONALIZED RBEC SAVINGS	Annual Total
1	RBEC Fuel Savings Total System	$82,000,000
2		
3	Jurisdictional %	95.55424%
4		
5	Jurisdictionalized RBEC Fuel Savings	$78,354,477
6		
7	Jurisdictionalized RBEC Fuel Savings Adjusted for Losses & Revenue Taxes	$78,543,407
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FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	3.263	1.00293	2.947
A	RS-1 all additional kWh	3.263	1.00293	3.947
A	GS-1, SL-2, GSCU-1, WIES-1	3.263	1.00293	3.273
A-1	SL-1, OL-1, PL-1 (1)	2.984	1.00293	2.992
B	GSD-1	3.263	1.00284	3.272
C	GSLD-1, CS-1	3.263	1.00186	3.269
D	GSLD-2, CS-2, OS-2, MET	3.263	0.99253	3.239
E	GSLD-3, CS-3	3.263	0.96479	3.148
A	GST-1 On-Peak	4.669	1.00293	4.683
	GST-1 Off-Peak	2.663	1.00293	2.671
A	RTR-1 On-Peak	-	-	1.410
	RTR-1 Off-Peak	-	-	(0.602)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.669	1.00283	4.682
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.663	1.00283	2.671
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.669	1.00186	4.678
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.663	1.00186	2.668
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.669	0.99328	4.638
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.663	0.99328	2.645
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.669	0.96479	4.505
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.663	0.96479	2.569
F	CILC-1(D), ISST-1(D) On-Peak	4.669	0.99253	4.634
	CILC-1(D), ISST-1(D) Off-Peak	2.663	0.99253	2.643

(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	6.001	1.00284	6.018
	GSD(T)-1 Off-Peak	2.777	1.00284	2.785
C	GSLD(T)-1 On-Peak	6.001	1.00186	6.012
	GSLD(T)-1 Off-Peak	2.777	1.00186	2.782
D	GSLD(T)-2 On-Peak	6.001	0.99328	5.961
	GSLD(T)-2 Off-Peak	2.777	0.99328	2.758

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Fuel Cost of System Generation	$233,108,385	$213,044,367	$257,918,712	$259,343,506	$279,253,240	$295,856,825	$321,498,280	$321,451,323	$298,810,379	$291,192,917	$233,978,087	$242,685,535	$3,248,141,556
2	Nuclear Fuel Disposal	2,409,819	2,176,613	1,587,537	1,860,399	2,347,859	2,272,121	2,347,859	2,347,859	2,146,193	1,826,155	2,332,085	2,409,819	26,064,319
3	RBEC Fuel Savings	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	6,833,333	82,000,000
4	Fuel Cost of Power Sold	(5,739,770)	(9,106,079)	(10,893,920)	(7,980,423)	(5,760,820)	(5,833,323)	(6,602,020)	(4,047,920)	(1,737,073)	(1,970,620)	(3,479,923)	(6,536,420)	(69,688,315)
5	Gain on Economy Sales	(993,750)	(1,657,500)	(1,948,750)	(1,193,750)	(901,250)	(650,000)	(823,750)	(565,000)	(203,750)	(290,000)	(637,500)	(1,215,000)	(11,080,000)
6	Fuel Cost of Purchased Power	9,032,496	8,624,221	9,398,040	9,481,790	13,524,421	15,397,625	16,147,779	15,798,587	16,191,274	13,504,351	8,721,822	8,501,088	144,323,495
7	Qualifying Facilities	9,945,865	8,880,867	10,309,866	5,997,865	10,849,865	13,256,860	14,016,861	13,746,860	13,771,859	9,839,862	6,976,866	8,973,866	126,567,361
8	Energy Cost of Economy Purchases	197,461	85,278	86,206	519,450	155,794	3,005,537	3,824,412	2,947,914	1,805,718	715,344	29,606	30,818	13,403,538
9	Total Fuel & Net Power Transactions	$254,793,840	$228,881,101	$273,291,024	$274,862,170	$306,302,441	$330,138,979	$357,242,754	$358,512,956	$337,617,933	$321,651,343	$254,754,376	$261,683,039	$3,559,731,955
10														
11	Incremental Personnel, Software and Hardware Costs	33,432	29,280	31,536	32,961	32,961	31,536	34,387	31,536	32,961	34,387	30,110	34,387	389,472
12	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	0	326,160	279,350	203,850	128,350	143,450	105,700	37,750	60,400	151,000	286,900	1,722,910
13	Total	33,432	29,280	357,696	312,311	236,811	159,886	177,837	137,236	70,711	94,787	181,110	321,287	2,112,382
14	Adjusted Total Fuel & Net Power Transactions	254,827,272	228,910,381	273,648,719	275,174,481	306,539,252	330,298,864	357,420,590	358,650,191	337,688,644	321,746,129	254,935,486	262,004,326	3,561,844,337
15														
16	System MWH Sales	8,985,918	7,947,739	7,864,510	7,931,770	9,091,100	9,818,071	10,760,888	10,705,544	10,396,265	9,730,435	8,866,980	8,668,474	110,767,695
17														
18	Cost per KWH (¢/KWH)	2.8359	2.8802	3.4795	3.4693	3.3719	3.3642	3.3215	3.3501	3.2482	3.3066	2.8751	3.0225	3.2156
19	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
20	Jurisdictional Cost (¢/KWH)	2.8406	2.8851	3.4854	3.4751	3.3776	3.3699	3.3271	3.3558	3.2537	3.3122	2.8800	3.0276	3.2210
21	True-Up (¢/KWH)	0.1392	0.1619	0.1633	0.1628	0.1411	0.1311	0.1199	0.1211	0.1249	0.1336	0.1467	0.1491	0.1396
22	Total (¢/KWH)	2.9798	3.0470	3.6487	3.6379	3.5187	3.5010	3.4470	3.4769	3.3786	3.4458	3.0267	3.1767	3.3606
23	Revenue Tax Factor (0.00072)	0.0021	0.0022	0.0026	0.0026	0.0025	0.0025	0.0025	0.0025	0.0024	0.0025	0.0022	0.0023	0.0024
24	Recovery Factor Adjusted for Taxes (¢/KWH)	2.9819	3.0492	3.6513	3.6405	3.5212	3.5035	3.4495	3.4794	3.3810	3.4483	3.0289	3.1790	3.3630
25	GPIF (¢/KWH)	0.0195	0.0227	0.0229	0.0228	0.0197	0.0184	0.0168	0.0170	0.0175	0.0187	0.0205	0.0209	0.0195
26	Jurisdictionalized Savings - RBEC (¢/KWH)	0.0000	0.0000	0.0000	0.0000	0.0000	(0.1195)	(0.1093)	(0.1104)	(0.1138)	(0.1217)	(0.1337)	(0.1359)	(0.1198)
27	Recovery Factor including GPIF (¢/KWH)	3.0014	3.0719	3.6742	3.6633	3.5409	3.4024	3.3570	3.3860	3.2847	3.3453	2.9157	3.0640	3.2627
28														
29	Recovery Factor Rounded to .001 (¢/KWH)	3.001	3.072	3.674	3.663	3.541	3.402	3.357	3.386	3.285	3.345	2.916	3.064	3.263
30														
31	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JUNE 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) RS-1 Standard	(3) Proposed Inverted Fuel Factors	(4) Target Fuel Revenues	(5) Rounded
1	First 1000 KWH	37,388,852,427	0.029472	$1,101,910,074.54	2.947
2	All Additional KWH	18,070,887,116	0.039472	$713,287,200.70	3.947
3	Total KWH	55,459,739,543		$1,815,197,275.24	
4					
5	Avg Fuel Factor	3.263			
6	RS-1 Loss Multiplier	1.00293			
7	Average Fuel Factor	3.273			
8					
9	Target Fuel Revenues	$1,815,197,275.24			
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COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	SEPT 13	PROPOSED [1], [2] JAN 14 - MAY 14	DIFFERENCE $	DIFFERENCE %	PROPOSED [1], [2] JUN 14 - DEC 14	DIFFERENCE $	DIFFERENCE %
BASE	$51.33	$52.48	$1.15	2.24%	$54.88	$2.40	4.57%
FUEL	$26.33	$30.67	$4.34	16.48%	$29.47	-$1.20	-3.91%
CONSERVATION	$2.33	$3.37	$1.04	44.64%	$3.37	$0.00	0.00%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%	$7.86	$0.00	0.00%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%	$2.30	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.07	$1.07	$0.00	0.00%	$1.07	$0.00	0.28%
SUBTOTAL	$92.73	$97.75	$5.02	5.41%	$98.95	$1.20	1.23%
GROSS RECEIPTS TAX	$2.38	$2.51	$0.13	5.46%	$2.54	$0.03	1.20%
TOTAL	**$95.11**	**$100.26**	$5.15	5.41%	**$101.49**	$1.23	1.23%

Note: [1] Base rate changes are based on estimated EPU increase.
[2] Based on estimates of the Conservation factor to be filed on September 10, 2013.

APPENDIX IV
FUEL COST RECOVERY
2014 E-SCHEDULES

TRADITIONAL FCR FACTOR CALCULATION
FOR THE PERIOD JANUARY 2014 THROUGH DECEMBER 2014

TJK-7
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-6
AUGUST 30, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 16
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-7

APPENDIX IV FUEL COST RECOVERY
E SCHEDULES
JANUARY 2014 – DECEMBER 2014
TABLE OF CONTENTS

PAGE(S)	SCHEDULES	SPONSOR
1	Schedule E1 Fuel & Purchased Power Cost Recovery Clause Calculation	T.J. Keith
2-3	Schedule E1-E Factors by Rate Group	T.J. Keith
4	Schedule E2 Monthly Summary of Fuel & Purchased Power Cost Recovery Clause Calculation	T.J. Keith / G. Yupp
5	Inverted Rate Calculation – RS-1	T.J. Keith
6	Schedule E10 Residential Bill Comparison	T.J. Keith

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) Dollars	(3) MWH	(4) Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,248,141,556	112,677,379	2.8827
2	Nuclear Fuel Disposal Costs (E2)	$26,064,319	27,766,399	0.0939
3	TOTAL COST OF GENERATED POWER	$3,274,205,875	112,677,379	2.9058
4	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$144,323,495	4,102,190	3.5182
5	Energy Cost of Economy Purchases (E9)	$13,403,538	278,500	4.8128
6	Payments to Qualifying Facilities (E8)	$126,567,361	2,940,405	4.3044
7	TOTAL COST OF PURCHASED POWER	$284,294,395	7,321,095	3.8832
8	TOTAL AVAILABLE MWH (LINE 3 + LINE 7)		119,998,473	
9	Fuel Cost of Economy Sales (E6)	($65,345,750)	(1,655,000)	3.9484
10	Gain from Off-System Sales (E6)	($11,080,000)	N/A	N/A
11	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,342,565)	(629,817)	0.6895
12	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,768,315)	(2,284,817)	3.5350
13	Incremental Personnel, Software, and Hardware Costs	$389,472	N/A	N/A
14	Variable Power Plant O&M Costs over 514,000 MW Threshold	$1,722,910	N/A	N/A
15	TOTAL INCREMENTAL OPTIMIZATION COSTS	2,112,382	N/A	N/A
16	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 3 + 7 + 12 + 15)	$3,479,844,337	117,713,657	2.9562
17	Net Unbilled Sales [1]	($31,293,303)	(1,058,567)	(0.0283)
18	Company Use [1]	$10,439,533	353,141	0.0094
19	T & D Losses [1]	$226,189,882	7,651,388	0.2042
20	SYSTEM MWH SALES	$3,479,844,337	110,767,695	3.1416
21	Wholesale MWH Sales	$154,705,528	4,924,470	3.1416
22	Jurisdictional MWH Sales	$3,325,138,809	105,843,225	3.1416
23	Jurisdictional Loss Multiplier	$5,619,485		1.00169
24	Jurisdictional MWH Sales Adjusted for Line Losses	$3,330,758,294	105,843,225	3.1469
25	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$147,765,613	105,843,225	0.1396
26	TOTAL JURISDICTIONAL FUEL COST	$3,478,523,907	105,843,225	3.2865
27	Revenue Tax Factor	$2,504,537		1.00072
28	Fuel Factor Adjusted for Taxes	$3,481,028,444	105,843,225	3.2889
29	GPIF [2]	$20,679,970	105,843,225	0.0195
30	Fuel Factor including GPIF (Line 28 + Line 29)	$3,501,708,414	105,843,225	3.3084
31	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.308
32				
33	[1] For Informational Purposes Only			
34	[2] Calculation Based on Jurisdictional KWH Sales			
35				
36	Note: Totals may not add due to rounding.			
37				
38				

FLORIDA POWER & LIGHT COMPANY
FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	3.308	1.00293	2.992
A	RS-1 all additional kWh	3.308	1.00293	3.992
A	GS-1, SL-2, GSCU-1, WIES-1	3.308	1.00293	3.318
A-1	SL-1, OL-1, PL-1 [1]	3.025	1.00293	3.034
B	GSD-1	3.308	1.00284	3.317
C	GSLD-1, CS-1	3.308	1.00186	3.314
D	GSLD-2, CS-2, OS-2, MET	3.308	0.99253	3.283
E	GSLD-3, CS-3	3.308	0.96479	3.192
A	GST-1 On-Peak	4.734	1.00293	4.748
	GST-1 Off-Peak	2.699	1.00293	2.707
A	RTR-1 On-Peak	-	-	1.430
	RTR-1 Off-Peak	-	-	(0.611)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	4.734	1.00283	4.747
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.699	1.00283	2.707
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	4.734	1.00186	4.743
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.699	1.00186	2.704
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	4.734	0.99328	4.702
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.699	0.99328	2.681
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	4.734	0.96479	4.567
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.699	0.96479	2.604
F	CILC-1(D), ISST-1(D) On-Peak	4.734	0.99253	4.699
	CILC-1(D), ISST-1(D) Off-Peak	2.699	0.99253	2.679

[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	6.083	1.00284	6.100
	GSD(T)-1 Off-Peak	2.815	1.00284	2.823
C	GSLD(T)-1 On-Peak	6.083	1.00186	6.094
	GSLD(T)-1 Off-Peak	2.815	1.00186	2.820
D	GSLD(T)-2 On-Peak	6.083	0.99328	6.042
	GSLD(T)-2 Off-Peak	2.815	0.99328	2.796

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	Fuel Cost of System Generation	$233,108,385	$213,044,367	$257,918,712	$259,343,506	$279,253,240	$295,856,825	$321,498,280	$321,451,323	$298,810,379	$291,192,917	$233,978,087	$242,685,535	$3,248,141,556
2	Nuclear Fuel Disposal	2,409,819	2,176,613	1,587,537	1,860,399	2,347,859	2,272,121	2,347,859	2,347,859	2,146,193	1,826,155	2,332,085	2,409,819	26,064,319
3	Fuel Cost of Power Sold	(5,739,770)	(9,106,079)	(10,893,920)	(7,980,423)	(5,760,820)	(5,833,323)	(6,602,020)	(4,047,920)	(1,737,073)	(1,970,620)	(3,479,923)	(6,536,420)	(69,688,315)
4	Gain on Economy Sales	(993,750)	(1,657,500)	(1,948,750)	(1,193,750)	(901,250)	(650,000)	(823,750)	(565,000)	(203,750)	(290,000)	(637,500)	(1,215,000)	(11,080,000)
5	Fuel Cost of Purchased Power	9,032,496	8,624,221	9,398,040	9,481,790	13,524,421	15,397,625	16,147,779	15,798,587	16,191,274	13,504,351	8,721,822	8,501,088	144,323,495
6	Qualifying Facilities	9,945,865	8,880,867	10,309,866	5,997,865	10,849,865	13,256,860	14,016,861	13,746,860	13,771,859	9,839,862	6,976,866	8,973,866	126,567,361
7	Energy Cost of Economy Purchases	197,461	85,278	86,206	519,450	155,794	3,005,537	3,824,412	2,947,914	1,805,718	715,344	29,606	30,818	13,403,538
8	Total Fuel & Net Power Transactions	$247,960,507	$222,047,768	$266,457,690	$268,028,837	$299,469,108	$323,305,645	$350,409,420	$351,679,622	$330,784,599	$314,818,009	$247,921,043	$254,849,706	$3,477,731,955
9														
10	Incremental Personnel, Software and Hardware Costs	33,432	29,280	31,536	32,961	32,961	31,536	34,387	31,536	32,961	34,387	30,110	34,387	389,472
11	Variable Power Plant O&M Costs over 514,000 MW Threshold	0	0	326,160	279,350	203,850	128,350	143,450	105,700	37,750	60,400	151,000	286,900	1,722,910
12	Total	33,432	29,280	357,696	312,311	236,811	159,886	177,837	137,236	70,711	94,787	181,110	321,287	2,112,382
13	Adjusted Total Fuel & Net Power Transactions	247,993,938	222,077,047	266,815,386	268,341,148	299,705,919	323,465,531	350,587,257	351,816,858	330,855,311	314,912,796	248,102,153	255,170,992	3,479,844,337
14														
15	System MWH Sales	8,985,918	7,947,739	7,864,510	7,931,770	9,091,100	9,818,071	10,760,888	10,705,544	10,396,265	9,730,435	8,866,980	8,668,474	110,767,695
16														
17	Cost per KWH (¢/KWH)	2.7598	2.7942	3.3927	3.3831	3.2967	3.2946	3.2580	3.2863	3.1824	3.2364	2.7980	2.9437	3.1416
18	Jurisdictional Loss Multiplier	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169	1.00169
19	Jurisdictional Cost (¢/KWH)	2.7645	2.7989	3.3984	3.3888	3.3023	3.3002	3.2635	3.2919	3.1878	3.2418	2.8028	2.9486	3.1469
20	True-Up (¢/KWH)	0.1392	0.1619	0.1633	0.1628	0.1411	0.1311	0.1199	0.1211	0.1249	0.1336	0.1467	0.1491	0.1396
21	Total (¢/KWH)	2.9037	2.9608	3.5617	3.5516	3.4434	3.4313	3.3834	3.4130	3.3127	3.3754	2.9495	3.0977	3.2865
22	Revenue Tax Factor (0.00072)	0.0021	0.0021	0.0026	0.0026	0.0025	0.0025	0.0024	0.0025	0.0024	0.0024	0.0021	0.0022	0.0024
23	Recovery Factor Adjusted for Taxes (¢/KWH)	2.9058	2.9629	3.5643	3.5542	3.4459	3.4338	3.3858	3.4155	3.3151	3.3778	2.9516	3.0999	3.2889
24	GPIF (¢/KWH)	0.0195	0.0227	0.0229	0.0228	0.0197	0.0184	0.0168	0.0170	0.0175	0.0187	0.0205	0.0209	0.0195
25	Recovery Factor including GPIF (¢/KWH)	2.9253	2.9856	3.5872	3.5770	3.4656	3.4522	3.4026	3.4325	3.3326	3.3965	2.9721	3.1208	3.3084
26														
27	Recovery Factor Rounded to .001 (¢/KWH)	2.925	2.986	3.587	3.577	3.466	3.452	3.403	3.433	3.333	3.397	2.972	3.121	3.308
28														
29	Note: Totals may not add due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) RS-1 Standard	(3) Proposed Inverted Fuel Factors	(4) Target Fuel Revenues	(5) Rounded
1	First 1000 KWH	37,388,852,427	0.029922	$1,118,735,058.13	2.992
2	All Additional KWH	18,070,887,116	0.039922	$721,419,099.90	3.992
3	Total KWH	55,459,739,543		$1,840,154,158.04	
4					
5	Avg Fuel Factor	3.308			
6	RS-1 Loss Multiplier	1.00293			
7	Average Fuel Factor	3.318			
8					
9	Target Fuel Revenues	$1,840,154,158.04			
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COMPANY: FLORIDA POWER & LIGHT COMPANY

	SEPT 13	PROPOSED [1], [2] JAN 14 - DEC 14	DIFFERENCE $	DIFFERENCE %
BASE	$51.33	$52.48	$1.15	2.24%
FUEL	$26.33	$29.92	$3.59	13.63%
CONSERVATION	$2.33	$3.37	$1.04	44.64%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%
STORM RESTORATION SURCHARGE	$1.07	$1.07	$0.00	0.00%
SUBTOTAL	$92.73	$97.00	$4.27	4.60%
GROSS RECEIPTS TAX	$2.38	$2.49	$0.11	4.62%
TOTAL	**$95.11**	**$99.49**	$4.38	4.61%

Note: [1] Base rate changes are based on estimated EPU increase.
[2] Based on estimates of the Conservation factor to be filed on September 10, 2013.

APPENDIX V

CAPACITY COST RECOVERY

JANUARY 2014 – DECEMBER 2014 FACTORS

TJK-8
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT _____
PAGES 1-13
AUGUST 30, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 17
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-8

APPENDIX V
CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION	SPONSOR
1	Revised 2013 Capacity Actual/Estimated True-up Calculation	T. J. Keith
2	2014 Projected Capacity Payments	T. J. Keith
3	Calculation of Energy & Demand Allocation % By Rate Class	T. J. Keith
4	Calculation of 2014 Capacity Recovery Factor	T. J. Keith
5-6	Calculation of Return and Capital Investments Depreciation and Taxes-Incremental Security	T.J. Keith
7	Calculation of Return and Capital Investments Depreciation and Taxes-Incremental Nuclear NRC Compliance	T.J. Keith
8-9	Capacity Costs – 2014 Projections	G. J. Yupp
10	Rate Case Allocation of Gas Turbine Production Revenue Requirement January 2014 through December 2014	T.J. Keith
11	Calculation of Revenue Impact for West County Energy Center Unit 3	T.J. Keith
12	Calculation of Capacity Cost Recovery Factor for West County Energy Center Unit 3	T.J. Keith
13	Calculation of Capacity Recovery Factor including West County Energy Center Unit 3 for January 2014 through December 2014	T.J. Keith

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

REVISED

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) Total
1	Payments to Non-cogenerators	$16,437,513	$16,618,240	$17,107,824	$16,482,672	$16,487,283	$16,076,979	$15,714,068	$16,214,757	$17,059,834	$16,492,116	$16,259,876	$16,286,036	$197,237,197
2	Payments to Co-generators	$25,038,297	$25,205,917	$20,512,305	$23,359,041	$22,728,373	$23,148,194	$23,388,910	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$23,087,688	$278,819,477
3	SJRPP Suspension Accrual	$0	$0	($2,582,946)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return on SJRPP Suspension Liability	($445,444)	($445,444)	($435,246)	($421,647)	($414,848)	($408,049)	($405,655)	($398,786)	($391,912)	($385,038)	($378,164)	($371,291)	($4,901,525)
5	Incremental Plant Security PSC Order No. 02-1761	$2,742,107	$3,070,332	$3,468,119	$3,248,334	$2,732,257	$3,485,081	$2,485,373	$5,208,263	$5,387,066	$4,104,789	$4,317,518	$6,176,809	$46,426,048
6	Incremental Nuclear NRC Compliance Costs O&M	$25,179	$174,820	($37,256)	($3,346)	$23,650	($83,471)	$18,082	($3,127)	$46,873	($3,127)	($3,127)	($56,471)	$98,678
7	Incremental Nuclear NRC Compliance Costs Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,587	$17,587
8	Transmission of Electricity by Others	$2,270,836	$2,203,512	$2,161,119	$1,343,872	$1,441,836	($627,741)	$1,138,719	$1,541,868	$1,399,703	$1,613,647	$2,021,776	$2,069,324	$18,578,470
9	Transmission Revenues from Capacity Sales	($329,135)	($578,809)	($845,612)	($380,813)	($477,335)	($249,378)	($294,350)	($176,250)	($86,250)	($92,500)	($225,000)	($422,500)	($4,157,931)
10	Total (Lines 1 through 9)	$45,739,352	$46,248,567	$39,348,308	$42,767,130	$41,660,233	$40,480,632	$41,184,165	$44,613,432	$45,642,019	$43,956,593	$44,219,584	$45,926,201	$521,786,216
11	Jurisdictional Separation Factor [(a)]	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	97.97032%	N/A
12	Jurisdictional CCR	$44,810,990	$45,309,869	$38,549,663	$41,899,094	$40,814,664	$39,659,005	$40,348,258	$43,707,922	$44,715,632	$43,064,414	$43,322,068	$44,994,046	$511,195,626
13	Nuclear Cost Recovery Costs	$12,249,674	$14,229,199	$14,667,616	$13,013,524	$12,802,720	$12,659,892	$12,293,132	$12,200,448	$12,000,152	$11,888,604	$11,726,916	$11,774,862	$151,506,739
14	Jurisdictional CCR	$57,060,664	$59,539,068	$53,217,280	$54,912,618	$53,617,383	$52,318,897	$52,641,390	$55,908,370	$56,715,784	$54,953,018	$55,048,985	$56,768,908	$662,702,365
15	CCR Revenues (Net of Revenue Taxes)	$52,434,454	$49,413,054	$49,832,052	$53,331,531	$58,351,845	$61,903,701	$65,986,930	$68,299,950	$66,148,216	$61,684,870	$55,930,151	$54,654,912	697,971,665
16	Prior Period True-up Provision	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($5,048,586)	($60,583,035)
17	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$47,385,867	$44,364,468	$44,783,466	$48,282,945	$53,303,259	$56,855,115	$60,938,344	$63,251,364	$61,099,629	$56,636,284	$50,881,565	$49,606,325	$637,388,630
18	True-up Provision for Month - Over/(Under) Recovery (Line 17 - Line 14)	($9,674,797)	($15,174,600)	($8,433,814)	($6,629,673)	($314,124)	$4,536,218	$8,296,954	$7,342,994	$4,383,845	$1,683,266	($4,167,420)	($7,162,583)	($25,313,735)
19	Interest Provision for Month	($4,128)	($6,193)	($6,371)	($5,832)	($5,367)	($4,266)	($3,080)	($2,268)	($1,813)	($1,476)	($1,317)	($1,343)	($43,456)
20	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	($60,583,035)	($65,213,374)	($75,345,580)	($78,737,179)	($80,324,099)	($75,595,003)	($66,014,466)	($52,672,006)	($40,282,694)	($30,852,076)	($24,121,700)	($23,241,851)	($60,583,035)
21	Deferred True-up - Over/(Under) Recovery	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)	($7,913,484)
22	Prior Period True-up Provision - Collected/(Refunded) this Month	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$5,048,586	$60,583,035
23	End of Period True-up - Over/(Under) Recovery (Sum of Lines 18 through 22)	($73,126,858)	($83,259,064)	($86,650,663)	($88,237,583)	($83,508,487)	($73,927,950)	($60,585,490)	($48,196,178)	($38,765,560)	($32,035,184)	($31,155,335)	($33,270,675)	($33,270,675)
24														
25	[(a)] As approved on Order No PSC-12-0664-FOF-EI													
26														
27	Totals may not add up due to rounding.													
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FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

Line No.	(1)	(2) January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	(14) Total
1	Capacity Payments To Non-Cogenerators	$16,233,478	$16,639,803	$16,494,020	$16,828,377	$16,185,974	$16,007,436	$16,028,756	$15,942,337	$16,787,414	$16,219,696	$15,987,456	$16,013,616	$195,368,363
2	Capacity Payments To Cogenerators	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$23,521,757	$282,261,087
3	SJRPP Suspension Accrual	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($860,982)	($10,331,784)
4	Return Requirements On SJRPP Suspension Liability	($364,417)	($357,543)	($350,669)	($343,795)	($336,921)	($330,047)	($323,173)	($316,299)	($309,426)	($302,552)	($295,678)	($288,804)	($3,919,323)
5	Incremental Plant Security Costs O&M	$4,294,461	$3,543,474	$4,241,372	$3,805,797	$3,733,986	$5,300,828	$5,162,205	$4,226,056	$3,950,143	$4,176,511	$4,185,604	$5,922,258	$52,542,693
6	Incremental Plant Security Costs Capital	$3,124	$8,572	$12,996	$17,559	$22,350	$31,572	$44,885	$55,194	$63,625	$77,576	$94,124	$115,123	546,699
7	Incremental Nuclear NRC Compliance Costs O&M	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$21,333	$256,000
8	Incremental Nuclear NRC Compliance Costs Capital	$33,765	$48,262	$61,195	$73,863	$86,180	$98,724	$113,743	$130,977	$148,661	$166,596	$184,272	$219,333	$1,365,570
9	Transmission Of Electricity By Others	$2,083,294	$2,010,384	$1,750,171	$1,828,046	$1,738,270	$1,603,399	$1,587,912	$1,609,105	$1,555,750	$1,765,340	$2,082,589	$2,113,496	$21,727,757
10	Transmission Revenues From Capacity Sales	($366,250)	($595,000)	($753,750)	($511,250)	($408,750)	($246,250)	($278,750)	($182,500)	($66,250)	($95,000)	($225,000)	($400,000)	($4,128,750)
11	System Total	$44,599,563	$43,980,060	$44,137,444	$44,380,705	$43,703,197	$45,147,770	$45,017,686	$44,146,978	$44,812,027	$44,690,276	$44,695,476	$46,377,130	$535,688,312
12	Jurisdictional % *													95.20688%
13	Jurisdictionalized Capacity Payments													$510,012,148
14	2012 FINAL TRUE-UP -- (Over)/Under Recovery													$7,913,484
15	2013 ACT/EST TRUE-UP -- (Over)/Under Recovery													$25,357,191
16	Nuclear Cost Recovery Clause													$43,461,246
17	Total (Lines 13+14+15+16)													$586,744,069
18	Revenue Tax Multiplier													1.00072
19	Total Recoverable Capacity Payments													$587,166,525
20														
21	*Calculation of Jurisdictional %													
22	.....AVG. 12CP													
23	.....AT GEN (MW).....%													
24	FPSC.....19,105.040.....95.206884%													
25	FERC.....961.828.....4.793116%													
26	TOTAL.....20,066.868.....100.00000%													
27														
28	* Based on 2014 projected Data													
29	Totals may not add up due to rounding.													
30														
31														
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE SCHEDULE	AVG 12CP Load Factor at Meter (%) [a]	Projected Sales at Meter (kwh) [b]	Projected AVG 12CP at Meter (kW) [c]	Demand Loss Expansion Factor [d]	Energy Loss Expansion Factor [e]	Projected Sales at Generation (kwh) [f]	Projected AVG 12CP at Generation (kW) [g]	Percentage of Sales at Generation (%) [h]	Percentage of Demand at Generation (%) [i]
RS1/RTR1	60.017%	55,459,739,543	10,548,782	1.07574702	1.05857569	58,708,332,054	11,347,821	52.46263%	59.39700%
GS1/GST1/WIES1	73.769%	6,126,227,507	948,015	1.07574702	1.05857569	6,485,075,510	1,019,824	5.79516%	5.33799%
GSD1/GSDT1/HLFT1	76.912%	25,762,255,228	3,823,703	1.07561796	1.05847562	27,268,719,075	4,112,844	24.36773%	21.52753%
OS2	86.219%	11,759,080	1,557	1.06570384	1.02863145	12,095,760	1,659	0.01081%	0.00869%
GSLD1/GSLDT1/CS1/CST1/HLFT2	77.411%	10,605,576,674	1,563,964	1.07421327	1.05744688	11,214,833,965	1,680,031	10.02174%	8.79365%
GSLD2/GSLDT2/CS2/CST2/HLFT3	91.599%	2,471,381,071	307,997	1.06229421	1.04839453	2,590,982,396	327,183	2.31534%	1.71255%
GSLD3/GSLDT3/CS3/CST3	90.819%	177,440,887	22,303	1.02281871	1.01832332	180,692,193	22,812	0.16147%	0.11940%
SST1T	80.082%	88,591,459	12,629	1.02281871	1.01832332	90,214,749	12,917	0.08062%	0.06761%
SST1D1/SST1D2/SST1D3	87.237%	9,856,390	1,290	1.03630873	1.02863145	10,138,593	1,337	0.00906%	0.00700%
CILC D/CILC G	95.745%	3,036,047,195	361,985	1.06183259	1.04827714	3,182,618,870	384,367	2.84404%	2.01186%
CILC T	98.609%	1,314,450,655	152,168	1.02281871	1.01832332	1,338,535,755	155,640	1.19614%	0.81466%
MET	74.716%	92,658,992	14,157	1.03630873	1.02863145	95,311,953	14,671	0.08517%	0.07679%
OL1/SL1/PL1	454.435%	630,606,760	15,841	1.07574702	1.05857569	667,544,986	17,041	0.59653%	0.08920%
SL2, GSCU1	100.920%	56,633,687	6,406	1.07574702	1.05857569	59,951,044	6,891	0.05357%	0.03607%
TOTAL		105,843,225,128	17,780,797			111,905,046,903	19,105,039	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2010-2012 load research data and 2014 projections.

[b] Projected kwh sales for the period January 2014 through December 2014.

[c] Calculated: Col(3)/(8760 hours * Col(2))

[d] Based on projected 2014 demand losses.

[e] Based on projected 2014 energy losses.

[f] Col(3) * Col(6)

[g] Col(4) * Col(5)

[h] Col(7) / Total for Col(7)

[i] Col(8) / Total for Col(8)

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Percentage of Sales at Generation (%) [a]	Percentage of Demand at Generation (%) [b]	Energy Related Cost ($) [c]	Demand Related Cost ($) [d]	Total Capacity Costs ($) [e]	Projected Sales at Meter (kwh) [f]	Billing KW Load Factor (%) [g]	Projected Billed KW at Meter (KW) [h]	Capacity Recovery Factor ($/KW) [i]	Capacity Recovery Factor ($/kwh) [j]	RDC ($/KW) [k]	SDD ($/KW) [l]
RS1/RTR1	52.46263%	59.39700%	$23,695,616	$321,931,681	$345,627,297	55,459,739,543	-	-	-	0.00623	-	-
GS1/GST1/WIES1	5.79516%	5.33799%	$2,617,480	$28,931,877	$31,549,356	6,126,227,507	-	-	-	0.00515	-	-
GSD1/GSDT1/HLFT1	24.36773%	21.52753%	$11,006,088	$116,679,201	$127,685,289	25,762,255,228	50.43267%	69,975,985	1.82	-	-	-
OS2	0.01081%	0.00869%	$4,882	$47,073	$51,956	11,759,080	-	-	-	0.00442	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	10.02174%	8.79365%	$4,526,485	$47,661,589	$52,188,074	10,605,576,674	55.65176%	26,105,529	2.00	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.31534%	1.71255%	$1,045,762	$9,282,021	$10,327,783	2,471,381,071	65.76804%	5,147,567	2.01	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.16147%	0.11940%	$72,930	$647,162	$720,093	177,440,887	75.40900%	322,335	2.23	-	-	-
SST1T	0.08062%	0.06761%	$36,412	$366,454	$402,866	88,591,459	14.06729%	862,697	-	-	$0.26	$0.12
SST1D1/SST1D2/SST1D3	0.00906%	0.00700%	$4,092	$37,925	$42,017	9,856,390	13.75824%	98,137	-	-	$0.27	$0.13
CILC D/CILC G	2.84404%	2.01186%	$1,284,556	$10,904,302	$12,188,858	3,036,047,195	73.97652%	5,622,012	2.17	-	-	-
CILC T	1.19614%	0.81466%	$540,254	$4,415,432	$4,955,687	1,314,450,655	76.69387%	2,347,798	2.11	-	-	-
MET	0.08517%	0.07679%	$38,469	$416,209	$454,679	92,658,992	63.58056%	199,637	2.28	-	-	-
OL1/SL1/PL1	0.59653%	0.08920%	$269,432	$483,442	$752,873	630,606,760	-	-	-	0.00119	-	-
SL2, GSCU1	0.05357%	0.03607%	$24,197	$195,501	$219,698	56,633,687	-	-	-	0.00388	-	-
TOTAL			$45,166,656	$541,999,869	$587,166,525	105,843,225,128		110,681,696				

[a] Obtained from Page 3, Col(9)

[b] Obtained from Page 3, Col(10)

[c] (Total Capacity Costs/13) * Col(2)

[d] (Total Capacity Costs/13 * 12) * Col(3)

[e] Col(4) + Col(5)

[f] Projected kwh sales for the period January 2014 through December 2014.

[g] (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))

[h] Col(7) / (Col(8) *730)

[i] Col(6) / Col(9)

[j] Col(6) / Col(7)

[k] RDC = Reservation Demand Charge - (Total Col 6)/(Page 2 Total Col 8)(.10)(Page 2 Col 5)/12 Months

[l] SDD = Sum of Daily Demand Charge - (Total Col 6)/(Page 2 Total Col 8)/(21 onpeak days)(Page 2 Col 5)/12 Months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2014

Return on Capital Investments, Depreciation and Taxes
Incremental Security 2014
(in Dollars)

Line			Beginning of Period Amount	January Estimate	February Estimate	March Estimate	April Estimate	May Estimate	June Estimate	Six Month Amount
1.	Investments									
	a.	Expenditures/Additions		$782,475	$582,446	$525,739	$617,424	$582,851	$1,727,326	$4,818,261
	b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (A)		$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing		$0	782,475	1,364,921	1,890,660	2,508,084	3,090,935	4,818,261	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$0	$782,475	$1,364,921	$1,890,660	$2,508,084	$3,090,935	$4,818,261	n/a
6.	Average Net Investment			391,238	1,073,698	1,627,791	2,199,372	2,799,510	3,954,598	n/a
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		2,613	7,171	10,872	14,689	18,698	26,412	$80,455
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		510	1,401	2,124	2,870	3,653	5,160	$15,718
8.	Investment Expenses									
	a.	Depreciation		0	0	0	0	0	0	$0
	b.	Amortization		0	0	0	0	0	0	$0
	c.	Dismantlement								
	d.	Property Expenses								
	e.	Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)			$3,124	$8,572	$12,996	$17,559	$22,350	$31,572	$96,173

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).

(B) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the estimated period is 4.9230% based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) The Debt Component for Jan. - Dec 2014 is 1.5658% based on the May 2013 ROR Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2014

Return on Capital Investments, Depreciation and Taxes
Incremental Security 2014
(in Dollars)

Line		Beginning of Period Amount	July Estimate	August Estimate	September Estimate	October Estimate	November Estimate	December Estimate	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,607,720	$974,719	$1,137,382	$1,440,448	$1,572,675	$2,149,673	$13,700,878
	b. Clearings to Plant		$0	$0	$0	$4,900,460	$1,196,547	$5,274,032	$11,371,039
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	4,900,460	6,097,007	11,371,039	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	3,675	11,918	26,391	n/a
4.	CWIP - Non Interest Bearing	$4,818,261	6,425,981	7,400,700	8,538,082	5,078,070	5,454,198	2,329,839	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,818,261	$6,425,981	$7,400,700	$8,538,082	$9,974,855	$11,539,287	$13,674,487	n/a
6.	Average Net Investment		5,622,121	6,913,341	7,969,391	9,256,468	10,757,071	12,606,887	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		37,549	46,173	53,227	61,823	71,845	84,200	435,272
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		7,336	9,021	10,398	12,078	14,036	16,449	85,036
8.	Investment Expenses								
	a. Depreciation		0	0	0	3,675	8,243	14,473	26,391
	b. Amortization		0	0	0	0	0	0	0
	c. Dismantlement								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$44,885	$55,194	$63,625	$77,576	$94,124	$115,123	546,699

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).

(B) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the estimated period is 4.9230% based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) The Debt Component for Jan. - Dec 2014 is 1.5658% based on the May 2013 ROR Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 THROUGH DECEMBER 2014

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
INCREMENTAL NUCLEAR NRC COMPLIANCE														
1. Investments														
a. Expenditures/Additions		$2,020,790	$1,610,944	$1,628,955	$1,544,348	$1,541,164	$1,601,266	$2,161,125	$2,156,267	$2,273,797	$2,219,094	$2,208,885	$6,574,213	$27,540,850
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	($1,063,826)	($139,702)	($136,245)	($138,737)	($1,779,343)	($3,257,853)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Incremental Plant-In-Service/Depreciation Base [a]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
3. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	N/A
4. CWIP - Non Interest Bearing	$13,218,806	$15,239,595	$16,850,540	$18,479,494	$20,023,843	$21,565,007	$23,166,273	$25,327,398	$26,419,839	$28,553,934	$30,636,783	$32,706,932	$37,501,802	N/A
5. Net Investment (Lines 2 - 3 + 4)	$13,218,806	$15,239,595	$16,850,540	$18,479,494	$20,023,843	$21,565,007	$23,166,273	$25,327,398	$26,419,839	$28,553,934	$30,636,783	$32,706,932	$37,501,802	N/A
6. Total Estimated Capital Expenditures Included in Base Rates [b]	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	N/A
7. Base Rate Capital Expenditures Closed to Plant-in-Service [c]	$0	$0	$0	$0	$0	$0	$0	$0	$1,063,826	$1,203,528	$1,339,773	$1,478,510	$3,257,853	N/A
8. Remaining Amount Included in Base Rates (Lines 6 - 7)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$8,936,174	$8,796,472	$8,660,227	$8,521,490	$6,742,147	N/A
9. Adjusted Net Investment (Lines 5 - 8)	$3,218,806	$5,239,595	$6,850,540	$8,479,494	$10,023,843	$11,565,007	$13,166,273	$15,327,398	$17,483,666	$19,757,462	$21,976,557	$24,185,442	$30,759,655	N/A
10. Average Net Investment		$4,229,200	$6,045,067	$7,665,017	$9,251,668	$10,794,425	$12,365,640	$14,246,836	$16,405,532	$18,620,564	$20,867,010	$23,080,999	$27,472,549	N/A
11. Return on Average Net Investment														
a. Equity Component grossed up for taxes [d]		$28,246	$40,374	$51,194	$61,791	$72,095	$82,589	$95,153	$109,571	$124,364	$139,368	$154,155	$183,486	$1,142,385
b. Debt Component (Line 10 x debt rate x 1/12) [e]		$5,518	$7,888	$10,002	$12,072	$14,085	$16,135	$18,590	$21,406	$24,297	$27,228	$30,117	$35,847	$223,185
12. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total System Recoverable Expenses (Lines 11 & 12)		$33,765	$48,262	$61,195	$73,863	$86,180	$98,724	$113,743	$130,977	$148,661	$166,596	$184,272	$219,333	$1,365,570

[a] Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.
[b] Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).
[c] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.
[d] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9230%, which is based on the May 2013 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

Florida Power & Light Company
Schedule E12 - Capacity Costs

2014 Projection

Contract			Capacity MW	Term Start	Term End	Contract Type
Cedar Bay			250	1/25/1994	12/31/2024	QF
Indiantown			330	12/22/1995	12/1/2025	QF
Broward North - 1991 Agreement			11	1/1/1993	12/31/2026	QF
Broward South - 1991 Agreement			3.5	1/1/1993	12/31/2026	QF
SWAPBC			40	1/1/2012	4/1/2032	QF

QF = Qualifying Facility

2014 Projection Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	10,467,750	125,613,000
ICL	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	11,552,802	138,633,627
BN-NEG '91	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	324,390	3,892,680
BS-NEG '91	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	103,215	1,238,580
SWAPBC	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	12,883,200
Total	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	23,521,757	282,261,087

Florida Power & Light Company
Schedule E12 - Capacity Costs **CONFIDENTIAL**

2014 Projection

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Southern Company - UPS Scherer	Other Entity	June 1, 2010	December 31, 2015
2	Southern Company - UPS Harris	Other Entity	June 1, 2010	December 31, 2015
3	Southern Company - UPS Franklin	Other Entity	June 1, 2010	December 31, 2015
4	JEA - SJRPP	Other Entity	April 2, 1982	September 30, 2021

2014 Capacity in MW

Contract	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
1	163	163	163	163	163	163	163	163	163	163	163	163
2	600	600	600	600	600	600	600	600	600	600	600	600
3	190	190	190	190	190	190	190	190	190	190	190	190
4	375	375	375	375	375	375	375	375	375	375	375	375
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328

2014 Capacity in Dollars

Contract	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
1	[redacted]											
2												
3												
4												
Total	16,233,478	16,639,803	16,494,020	16,828,377	16,185,974	16,007,436	16,028,756	15,942,337	16,787,414	16,219,696	15,987,456	16,013,616

Total Capacity Payments to Non-Cogenerators for 2014	195,368,363

FLORIDA POWER & LIGHT COMPANY
RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT
JANUARY 2014 THROUGH DECEMBER 2014

	Rate	Demand & Energy Component[1] $000s	Allocation[2]	Allocation of WC3 Revenue Requirement @ 10.5% ROE [3]
	(a)	(b)	(c)	(d)
1	CILC-1D	22,378	2.083%	$3,316,762
2	CILC-1G	1,442	0.134%	$213,693
3	CILC-1T	9,888	0.921%	$1,465,532
4	GS1	61,812	5.754%	$9,161,544
5	GSCU-1	288	0.027%	$42,698
6	GSD1	237,906	22.148%	$35,261,321
7	GSLD1	105,089	9.783%	$15,575,765
8	GSLD2	20,042	1.866%	$2,970,566
9	GSLD3	1,575	0.147%	$233,409
10	MET	936	0.087%	$138,795
11	OL-1	274	0.025%	$40,578
12	OS-2	101	0.009%	$14,949
13	RS1	609,861	56.774%	$90,390,743
14	SL-1	1,438	0.134%	$213,103
15	SL-2	256	0.024%	$37,943
16	SST-DST	49	0.005%	$7,212
17	SST-TST	849	0.079%	$125,778
18				
19	Total	1,074,183	100.0%	$159,210,391

Notes:
[1] Other Production revenue requirements as approved in Docket 120015-EI 2013
[2] Calculated: Col (c) / TotalCol (c)
[3] Calculated: Col (b) * Col (c)

Calculation differences are due to rounding

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF REVENUE IMPACT FOR WEST COUNTY 3

	(a)	Total Revenue[1] (b)	Total WC3 Costs[2] (c)		% Increase[3] (d)
1	RS1/RTR-1	$5,545,061,516	$90,390,743		1.63%
2	GS1/GST1	$603,514,952	$9,161,544		1.52%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$2,114,775,715	$35,261,321		1.67%
4	OS2	$1,489,330	$14,949		1.00%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$785,102,939	$15,575,765		1.98%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$168,982,932	$2,970,566		1.76%
7	GSLD3/GSLDT3/CS3/CST3	$11,167,080	$233,409		2.09%
8	SST1T	$7,437,796	$125,778		1.69%
9	SST1D1/SST1D2/SST1D3	$1,144,222	$7,212		0.63%
10	CILC D/CILC G	$186,089,149	$3,530,454		1.90%
11	CILC T	$69,377,081	$1,465,532		2.11%
12	MET	$7,670,568	$138,795		1.81%
13	OL1/SL1/PL1	$119,675,788	$253,681		0.21%
14	SL2, GSCU1	$4,876,565	$80,641		1.65%
15					
16	TOTAL	$9,626,365,633	$159,210,391		1.65%
				1.5x	2.48%
				Max	2.11%

Notes

[1] Based on Projections of 2014 base and clause revenues.

[2] 2014 WC3 Revenue Requirements by rate class

[3] Calculated: Col (c) * Col (d)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY 3
JANUARY 2014 THROUGH DECEMBER 2014

	Rate Schedule	(1) Projected Billed Sales at Meter (kWh)	(2) Billing kW Load Factor (%)	(3) Projected Billed kW at Meter (KW)	(4) Total Capacity Costs ($)	(5) Capacity Recovery Factor ($/KW)	(6) Capacity Recovery Factor ($/kWh)
1	RS1/RTR-1	55,459,739,543	-	-	$90,390,743		0.00163
2	GS1/GST1	6,126,227,507	-	-	$9,161,544		0.00150
3	GSD1/GSDT1/HLFT1 (21-499 kW)	25,762,255,228	50.43267%	69,975,985	$35,261,321	0.50	
4	OS2	11,759,080	-	-	$14,949		0.00127
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	10,605,576,674	55.65176%	26,105,529	$15,575,765	0.60	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	2,471,381,071	65.76804%	5,147,567	$2,970,566	0.58	
7	GSLD3/GSLDT3/CS3/CST3	177,440,887	75.40900%	322,335	$233,409	0.72	
8	SST1T/ISST1T	88,591,459	14.06729%	862,697	$125,778		
9	SST1D1/SST1D2/SST1D3/ISST1D	9,856,390	13.75824%	98,137	$7,212		
10	CILC D/CILC G	3,036,047,195	73.97652%	5,622,012	$3,530,454	0.63	
11	CILC T	1,314,450,655	76.69387%	2,347,798	$1,465,532	0.62	
12	MET	92,658,992	63.58056%	199,637	$138,795	0.70	
13	OL1/SL1/PL1	630,606,760	-	-	$253,681		0.00040
14	SL2, GSCU1	56,633,687	-	-	$80,641		0.00142
15							
16	TOTAL	105,843,225,128		110,681,696	$159,210,391		
17							
18							
19							

(1) Projected kwh sales for the period January 2014 through December 2014
(2) Billing kW Load Factor based on load research data
(3) Calculated: Col(1)/(730 hours * Col(2))
(4) Per Rate Case Allocation Worksheet
(5) Calculated: Col (4) / Col (3)
(6) Calculated: Col (4) / Col (1)

Calculation differences are due to rounding

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 4)/(Total Proj Ave 12CP at Generation)(.10) (Demand Loss Factor/12) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 4)/(Total Proj Ave 12CP at Generation)/(21 onpeak days) (Demand Loss Factor/12) / 12 months

	CAPACITY RECOVERY FACTOR	
	RDC	SDD
	** ($/kw)	** ($/kw)
SST1T/ISST1T	$0.07	$0.03
SST1D1/SST1D2/SST1D3/ISST1D	$0.07	$0.03

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
INCLUDING WEST COUNTY ENERGY CENTER UNIT 3

ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2014 - Dec 2014 Capacity Recovery Factor				2014 WCEC-3 Capacity Recovery Factor				Total Jan 2014 - Dec 2014 Capacity Recovery Factor			
	($KW)	($/kwh)	RDC ($/KW) [1]	SDD ($/KW) [2]	($KW)	($/kwh)	RDC ($/KW)	SDD ($/KW)	($KW)	($/kwh)	RDC ($/KW) [1]	SDD ($/KW) [2]
RS1/RTR1	-	0.00623	-	-	-	0.00163	-	-	-	0.00786	-	-
GS1/GST1/WIES1	-	0.00515	-	-	-	0.00150	-	-	-	0.00665	-	-
GSD1/GSDT1/HLFT1	1.82	-	-	-	0.50	-	-	-	2.32	-	-	-
OS2	-	0.00442	-	-	-	0.00127	-	-	-	0.00569	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	2.00	-	-	-	0.60	-	-	-	2.60	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.01	-	-	-	0.58	-	-	-	2.59	-	-	-
GSLD3/GSLDT3/CS3/CST3	2.23	-	-	-	0.72	-	-	-	2.95	-	-	-
SST1T	-	-	$0.26	$0.12	-	-	$0.07	$0.03	-	-	$0.33	$0.15
SST1D1/SST1D2/SST1D3	-	-	$0.27	$0.13	-	-	$0.07	$0.03	-	-	$0.34	$0.16
CILC D/CILC G	2.17	-	-	-	0.63	-	-	-	2.80	-	-	-
CILC T	2.11	-	-	-	0.62	-	-	-	2.73	-	-	-
MET	2.28	-	-	-	0.70	-	-	-	2.98	-	-	-
OL1/SL1/PL1	-	0.00119	-	-	-	0.00040	-	-	-	0.00159	-	-
SL2, GSCU1	-	0.00388	-	-	-	0.00142	-	-	-	0.00530	-	-

[1] RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months

[2] SDD=((Total Capacity Costs)/(Projected Avg 12 CP @gen)/(21 onpeak days)(demand loss expansion factor))/12 months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

APPENDIX VI

2014 REVENUE REQUIREMENT CALCULATION FOR WEST COUNTY ENERGY CENTER UNIT 3

TJK-9
DOCKET NO. 130001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT _____
PAGES 1-2
AUGUST 30, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 18
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Terry J. Keith - TJK-9

Line No.	WCEC3 Revenue Requirement Calculation	2014
1	Jurisdictional Adjusted Rate Base	$727,516,144
2	Rate of Return on Rate Base	8.701%
3	Required Jurisdictional Net Operating Income	63,301,616
4	Required Net Operating Income	63,301,616
5	Jurisdictional Adjusted Net Operating Income (Loss)	(34,127,805)
6	Net Operating Income Deficiency (Excess)	97,429,421
7	Net Operating Income Multiplier	1.63411
8	2013 Revenue Requirement	$159,210,391

Note:

The Rate of Return was calculated using the Settlement Agreement ROE of 10.5%, as approved in Order No. PSC-13-0023-S-EI.

Line No.	Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
1	Long Term Debt	44.200%	6.430%	2.84206%	2.84206%	1.84450%
2	Common Equity	55.800%	10.500%	5.85900%	9.53846%	5.85900%
3	Total	100.000%		8.70106%	12.38052%	7.70350%
4						
6						
7	**Assumptions**					
8	Income Tax Rate	38.575%				
9	Production Depreciation Rate	4.000%				
10	Transmission Depreciation Rate	2.500%				
11	Rate of Return	8.70106%				
12						
13						

14	Net Plant	6/01/2011	12/31/2011	5/31/2012	12/31/2012	12/31/2013	12/31/2014
15	Production Plant	819,157,500	819,157,500	819,157,500	819,157,500	819,157,500	819,157,500
16	Transmission Plant	45,570,260	45,570,260	45,570,260	45,570,260	45,570,260	45,570,260
17	Production Reserve	0	(19,113,675)	(32,766,300)	(51,879,975)	(84,646,275)	(117,412,575)
18	Transmission Reserve	0	(664,566)	(1,139,257)	(1,803,823)	(2,943,079)	(4,082,336)
19	Deferred Taxes	9,376,790	4,664,390	(450,838)	(5,746,400)	(14,504,962)	(23,263,524)
20	Net Plant	874,104,550	849,613,909	830,371,366	805,297,562	762,633,444	719,969,325
21							
22							

23		6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013	12/31/2013-12/31/2014
24	**Average Rate Base**	861,859,229	852,237,958	827,455,735	819,157,500	783,965,503	741,301,384
25	Juris Factor	0.981404	0.981404	0.981404	0.981404	0.981404	0.981404
26	**Juris Rate Base**	845,832,095	836,389,741	812,068,369	803,924,447	769,386,880	727,516,144
27							
28	**Juris Interest Expense**	14,022,782	23,770,698	23,079,470	9,520,006	21,866,437	20,676,445
29	**Income Tax - Interest Expense**	(5,409,288)	(9,169,547)	(8,902,906)	(3,672,342)	(8,434,978)	(7,975,939)
30							
31							

32	**Operating Expenses**	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013	12/31/2013-12/31/2014
33	Other O&M - FOM, CAP, VOM, Prop Ins	11,041,700	19,123,583	19,396,520	8,081,883	19,774,240	19,759,190
34	Depreciation	19,778,241	33,905,557	33,905,557	14,127,315	33,905,557	33,905,557
35	Taxes Other Than Income Taxes - Prop Tax	9,079,640	15,416,761	15,209,090	6,337,121	14,598,800	13,988,490
36	Total Operating Expenses	39,899,581	68,445,901	68,511,167	28,546,319	68,278,597	67,653,237
37							
38	**Juris Operating Expenses**	39,149,725	67,159,426	67,223,284	28,009,702	66,994,769	66,381,049
39	**Income Tax - Operating Expenses**	(15,102,006)	(25,906,749)	(25,931,382)	(10,804,742)	(25,843,232)	(25,606,490)
40							
41	**Other Income Taxes - Def Taxes**	790,050	1,354,370	1,354,370	564,320	1,354,370	1,354,370
42	**Juris Other Income Taxes**	775,358	1,329,184	1,329,184	553,826	1,329,184	1,329,184
43							
44							

45	**Juris Net Operating Income**	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013	12/31/2013-12/31/2014
46	Operating Expenses	(39,149,725)	(67,159,426)	(67,223,284)	(28,009,702)	(66,994,769)	(66,381,049)
47	Income Tax - Operating Expenses	15,102,006	25,906,749	25,931,382	10,804,742	25,843,232	25,606,490
48	Income Tax - Interest Expense	5,409,288	9,169,547	8,902,906	3,672,342	8,434,978	7,975,939
49	Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)	(553,826)	(1,329,184)	(1,329,184)
50	**Juris Net Operating Income**	(19,413,788)	(33,412,315)	(33,718,181)	(14,086,443)	(34,045,743)	(34,127,805)

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2012

JCB-1
DOCKET NO. 130001-EI
FPL Witness: J. Carine Bullock
Exhibit No.: _____
Pages 1 - 18
May 13, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 19
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Charles R. Rote - JCB-1

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2012

INDEX OF MANUAL PAGES	TITLES
6.203.001	Index of Manual Pages
6.203.002	GPIF Reward/(Penalty) Table (Actual)
6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
6.203.004	Derivation of System Actual GPIF Points
6.203.005	Actual Equivalent Availability and Adjustments Summary
6.203.006	EAF Adjustment Documentation
6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
6.203.008 - 6.203.017	GPIF Units Points Tables
6.203.018	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2012

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)		GENERATING PERFORMANCE INCENTIVE FACTOR ($000)	
+ 10		91,083		46,380	
+ 9		81,975		41,742	
+ 8		72,866		37,104	
+ 7		63,758		32,466	
+ 6		54,650		27,828	
+ 5	<——— 4.46	45,542	<——— 46,363.302	23,190	<——— 20,679.970
+ 4		36,433		18,552	
+ 3		27,325		13,914	
+ 2		18,217		9,276	
+ 1		9,108		4,638	
0		0		0	
- 1		(9,108)		(4,638)	
- 2		(18,217)		(9,276)	
- 3		(27,325)		(13,914)	
- 4		(36,433)		(18,552)	
- 5		(45,542)		(23,190)	
- 6		(54,650)		(27,828)	
- 7		(63,758)		(32,466)	
- 8		(72,866)		(37,104)	
- 9		(81,975)		(41,742)	
- 10		(91,083)		(46,380)	

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2012

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 10,849,749,770	
LINE 2	MONTH OF January	2012	$ 10,983,930,940	
LINE 3	MONTH OF February	2012	$ 11,043,325,330	
LINE 4	MONTH OF March	2012	$ 11,128,965,610	
LINE 5	MONTH OF April	2012	$ 11,196,334,650	
LINE 6	MONTH OF May	2012	$ 11,333,068,500	
LINE 7	MONTH OF June	2012	$ 11,681,736,330	
LINE 8	MONTH OF July	2012	$ 11,828,681,570	
LINE 9	MONTH OF August	2012	$ 11,987,094,020	
LINE 10	MONTH OF September	2012	$ 12,073,906,876	
LINE 11	MONTH OF October	2012	$ 12,172,856,430	
LINE 12	MONTH OF November	2012	$ 12,463,562,700	
LINE 13	MONTH OF December	2012	$ 12,530,193,155	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 11,636,415,837	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 47,394,364	
LINE 18	JURISDICTIONAL SALES		102,225,549,000	KWH
LINE 19	TOTAL SALES		104,462,720,986	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		97.86%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 46,380,125	

JANUARY THROUGH DECEMBER, 2012

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Ft. Myers 2	EAF	6.90	5.60	.3864
Ft. Myers 2	ANOHR	3.51	0.00	.0000
Martin 8	EAF	5.86	3.20	.1875
Martin 8	ANOHR	7.18	3.16	.2269
Manatee 3	EAF	5.84	6.00	.3504
Manatee 3	ANOHR	6.42	0.00	.0000
Sanford 4	EAF	3.80	-1.50	-.0570
Sanford 4	ANOHR	3.19	0.00	.0000
Scherer 4	EAF	4.38	10.00	.4380
Scherer 4	ANOHR	2.17	0.00	.0000
St. Lucie 1	EAF	9.53	10.00	.9530
St. Lucie 1	ANOHR	2.19	0.00	.0000
St. Lucie 2	EAF	5.32	10.00	.5320
St. Lucie 2	ANOHR	1.97	1.32	.0260
Turkey Point 3	EAF	6.03	10.00	.6030
Turkey Point 3	ANOHR	2.53	0.46	.0116
Turkey Point 4	EAF	7.56	10.00	.7560
Turkey Point 4	ANOHR	4.50	0.00	.0000
Turkey Point 5	EAF	5.62	0.80	.0450
Turkey Point 5	ANOHR	5.50	0.00	.0000
GPIF System Total:		100		4.46

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2012

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED OUTAGE ADJ TO	ADJUSTED ACTUAL		POINTS FROM	ORIGINAL PLANNED OUTAGE	ACTUAL OUTAGE	ACTUAL FUEL SAVINGS/ (LOSS)
UNIT	FOF	MOF	POF	EAF	EAF [1]	EAF	TARGET EAF	TABLES	DATES	DATES	($000)
Ft. Myers 2	0.3	4.8	1.9	93.0	0.0	93.0	91.6	5.60	02/04/12 - 02/10/12; 02/11/12 - 02/17/12 02/12/12 - 02/18/12; 02/19/12 - 02/25/12	10/21/12-10/28/12; 10/20/12-10/27/12 12/10/12-12/16/12; 12/11/12-12/17/12 10/29/12-11/05/12; 10/28/12-11/04/12	3,519.0
Martin 8	1.5	4.4	2.5	91.6	0.6	92.2	91.4	3.20	11/26/12 - 12/23/12	9/22/12-9/29/12; 10/22/12-11/21/12	1,706.9
Manatee 3	0.0	3.6	2.1	94.3	1.1	95.4	93.9	6.00	11/03/12 - 11/09/12; 11/10/12 - 11/16/12	11/9/12-11/28/12; 11/28/12-12/11/12	3,192.0
Sanford 4	0.3	3.8	2.6	93.3	-1.1	92.2	92.5	-1.50	02/18/12 - 02/24/12; 05/26/12 - 06/20/12 06/21/12 - 06/27/12; 11/26/12 - 12/09/12	11/28/12-12/14/12; 10/9/12-11/3/12	(519.2)
Scherer 4	0.9	1.2	18.8	79.1	-4.6	74.5	72.5	10.00	03/02/12 - 05/26/12	3/2/12/-5/9/12	3,987.0
St. Lucie 1	2.1	0.0	39.1	58.8	13.7	72.5	68.7	10.00	01/01/12 - 04/01/12	1/1/12-4/21/12	8,679.0
St. Lucie 2	2.2	0.0	31.3	66.5	0.4	66.9	60.1	10.00	07/09/12 - 10/30/12	8/5/12-11/23/12	4,849.0
Turkey Point 3	0.9	0.0	63.2	35.9	19.1	55.0	49.9	10.00	01/30/12 - 07/08/12	2/26/12-9/5/12	5,488.0
Turkey Point 4	0.0	0.0	16.0	84.0	0.4	84.4	78.0	10.00	11/05/12 - 12/31/12	11/5/12-12/31/12	6,889.0
Turkey Point 5	0.1	5.1	0.9	93.9	-1.1	92.8	92.6	0.80	03/17/12 - 03/23/12; 03/24/12 - 03/30/12 03/24/12 - 03/30/12; 06/01/12 - 06/10/12	11/26/12-12/12/12	409.8
											38,200.610

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGET DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2012

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Ft. Myers 2	8784	27.2	417.9	165.5	1.9	168.0	93.0
Martin 8	8784	132.8	383.0	220.5	1.9	168.0	92.2
Manatee 3	8784	3.9	312.8	187.8	1.0	84.0	95.4
Sanford 4	8784	25.8	335.4	228.8	3.7	324.0	92.2
Scherer 4	8784	79.8	106.5	1649.6	23.5	2064.0	74.5
St. Lucie 1	8784	188.0	0.0	3432.5	24.9	2184.0	72.5
St. Lucie 2	8784	191.5	0.0	2753.3	30.9	2712.0	66.9
Turkey Point 3	8784	74.7	0.0	5553.7	43.7	3840.0	55.0
Turkey Point 4	8784	0.0	0.0	1404.7	15.6	1368.0	84.4
Turkey Point 5	8784	6.9	449.4	80.7	2.1	186.0	92.8

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2012

1	2	3	4	5	6	7	8	9	
		ACTUAL		TARGET [2]	ADJUST.[3]		ADJUST.[5]	GPIF[6]	ACTUAL
UNIT	HEAT RATE [1] FORMULA	NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET [4] ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	POINTS FROM TABLE	FUEL SAV./(LOSS) $000
Ft. Myers 2	ANOHR= -9.31 x NOF + 8,001	79.4	7,258	7,262	-4	7,105	7,101	0.00	0.0
Martin 8	ANOHR= -5.78 x NOF + 7,573	77.4	7,021	7,126	-105	7,025	6,920	3.16	2065.7
Manatee 3	ANOHR= -2.46 x NOF + 7,162	78.0	6,964	6,970	-6	6,930	6,924	0.00	0.0
Sanford 4	ANOHR= -7.12 x NOF + 7,928	73.1	7,404	7,408	-4	7,252	7,248	0.00	0.0
Scherer 4	ANOHR= -16.22 x NOF + 11,497	78.3	10,290	10,227	63	9,948	10,011	0.00	0.0
St. Lucie 1	ANOHR= -34.86 x NOF + 14,285	97.4	10,824	10,890	-66	10,771	10,705	0.00	1997.0
St. Lucie 2	ANOHR= -21.94 x NOF + 12,940	101.5	10,632	10,713	-81	10,724	10,643	1.32	1793.0
Turkey Point 3	ANOHR= -93.86 x NOF + 20,627	101.7	11,003	11,081	-78	10,875	10,797	0.46	2307.0
Turkey Point 4	ANOHR= -76.05 x NOF + 18,754	101.9	11,046	11,005	41	11,263	11,304	0.00	0.0
Turkey Point 5	ANOHR= -11.56 x NOF + 7,987	75.9	7,116	7,110	6	6,936	6,942	0.00	0.0

8,162.692

1) THESE FORMULAS ARE AS APPROVED BY THE COMMISSION IN THE PROJECTION FILING AND ARE BASED ON MONTHLY ACTUAL DATA
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).
4) AT TARGET NOF AS APPROVED BY THE COMMISSION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM THE GPIF POINT TABLES USING THE COMMISSION APPROVED TARGETS.
7) ST. LUCIE 1, ST. LUCIE 2 AND TURKEY POINT 3 FUEL SAVINGS REPRESENT THE SAVINGS FROM ACTUAL, UNADJUSTED HEAT RATE PERFORMANCE

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Ft. Myers 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	6,284.00	94.1	+10	3200.00	7016
+9	5,655.60	93.9	+9	2880.00	7017
+8	5,027.20	93.6	+8	2560.00	7019
+7	4,398.80	93.4	+7	2240.00	7020
+6	3,770.40	93.1	+6	1920.00	7022
+5	3,142.00 <- Fuel Sav/(Loss) 3,519.0	92.9 <- Adj. Act. EAF= 93.0	+5	1600.00	7023
+4	2,513.60	92.6	+4	1280.00	7024
+3	1,885.20	92.4	+3	960.00	7026
+2	1,256.80	92.1	+2	640.00	7027
+1	628.40	91.9	+1	320.00	7029
				0.00 <- Fuel Sav/(Loss) 0	7030 <- Adj. Act. HR=7101
0	0.00	91.6	0	0.00	7105
				(0.00)	7180
-1	(-628.40)	91.4	-1	(-320.00)	7181
-2	(-1,256.80)	91.1	-2	(-640.00)	7183
-3	(-1,885.20)	90.9	-3	(-960.00)	7184
-4	(-2,513.60)	90.6	-4	(-1280.00)	7186
-5	(-3,142.00)	90.4	-5	(-1600.00)	7187
-6	(-3,770.40)	90.1	-6	(-1920.00)	7188
-7	(-4,398.80)	89.9	-7	(-2240.00)	7190
-8	(-5,027.20)	89.6	-8	(-2560.00)	7191
-9	(-5,655.60)	89.4	-9	(-2880.00)	7193
-10	(-6,284.00)	89.1	-10	(-3200.00)	7194
	WEIGHTING FACTOR =	6.90		WEIGHTING FACTOR =	3.51

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Martin 8

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,334.00		93.9		+10	6537.00		6855	
+9	4,800.60		93.7		+9	5883.30		6865	
+8	4,267.20		93.4		+8	5229.60		6874	
+7	3,733.80		93.2		+7	4575.90		6884	
+6	3,200.40		92.9		+6	3922.20		6893	
+5	2,667.00		92.7		+5	3268.50		6903	
+4	2,133.60		92.4		+4	2614.80	<- Fuel Sav/(Loss) 2,065.7	6912	<- Adj. Act. HR=6920
+3	1,600.20	<- Fuel Sav/(Loss) 1,706.9	92.2	<- Adj. Act. EAF= 92.2	+3	1961.10		6922	
+2	1,066.80		91.9		+2	1307.40		6931	
+1	533.40		91.7		+1	653.70		6941	
						0.00		6950	
0	0.00		91.4		0	0.00		7025	
						(0.00)		7100	
-1	(-533.40)		91.2		-1	(-653.70)		7110	
-2	(-1,066.80)		90.9		-2	(-1307.40)		7119	
-3	(-1,600.20)		90.7		-3	(-1961.10)		7129	
-4	(-2,133.60)		90.4		-4	(-2614.80)		7138	
-5	(-2,667.00)		90.2		-5	(-3268.50)		7148	
-6	(-3,200.40)		89.9		-6	(-3922.20)		7157	
-7	(-3,733.80)		89.7		-7	(-4575.90)		7167	
-8	(-4,267.20)		89.4		-8	(-5229.60)		7176	
-9	(-4,800.60)		89.2		-9	(-5883.30)		7186	
-10	(-5,334.00)		88.9		-10	(-6537.00)		7195	
	WEIGHTING FACTOR =		5.86			WEIGHTING FACTOR =		7.18	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Manatee 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	5,320.00	96.4	+10	5843.00	6774
+9	4,788.00	96.2	+9	5258.70	6782
+8	4,256.00	95.9	+8	4674.40	6790
+7	3,724.00	95.7	+7	4090.10	6798
+6	3,192.00 <- Fuel Sav/(Loss) 3,192.0	95.4 <- Adj. Act. EAF= 95.4	+6	3505.80	6806
+5	2,660.00	95.2	+5	2921.50	6815
+4	2,128.00	94.9	+4	2337.20	6823
+3	1,596.00	94.7	+3	1752.90	6831
+2	1,064.00	94.4	+2	1168.60	6839
+1	532.00	94.2	+1	584.30	6847
				0.00 <- Fuel Sav/(Loss) 0	6855 <- Adj. Act. HR=6924
0	0.00	93.9	0	0.00	6930
				(0.00)	7005
-1	(-532.00)	93.7	-1	(-584.30)	7013
-2	(-1,064.00)	93.4	-2	(-1168.60)	7021
-3	(-1,596.00)	93.2	-3	(-1752.90)	7029
-4	(-2,128.00)	92.9	-4	(-2337.20)	7037
-5	(-2,660.00)	92.7	-5	(-2921.50)	7046
-6	(-3,192.00)	92.4	-6	(-3505.80)	7054
-7	(-3,724.00)	92.2	-7	(-4090.10)	7062
-8	(-4,256.00)	91.9	-8	(-4674.40)	7070
-9	(-4,788.00)	91.7	-9	(-5258.70)	7078
-10	(-5,320.00)	91.4	-10	(-5843.00)	7086
	WEIGHTING FACTOR =	5.84		WEIGHTING FACTOR =	6.42

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Sanford 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	3,461.00	94.5	+10	2907.00	7140
+9	3,114.90	94.3	+9	2616.30	7144
+8	2,768.80	94.1	+8	2325.60	7147
+7	2,422.70	93.9	+7	2034.90	7151
+6	2,076.60	93.7	+6	1744.20	7155
+5	1,730.50	93.5	+5	1453.50	7159
+4	1,384.40	93.3	+4	1162.80	7162
+3	1,038.30	93.1	+3	872.10	7166
+2	692.20	92.9	+2	581.40	7170
+1	346.10	92.7	+1	290.70	7173
				0.00 <- Fuel Sav/(Loss) 0	7177 <- Adj. Act. HR=7248
0	0.00	92.5	0	0.00	7252
				(0.00)	7327
-1	(-346.10)	92.3	-1	(-290.70)	7331
-2	(-692.20) <- Fuel Sav/(Loss) (519.2)	92.1 <- Adj. Act. EAF= 92.2	-2	(-581.40)	7334
-3	(-1,038.30)	91.9	-3	(-872.10)	7338
-4	(-1,384.40)	91.7	-4	(-1162.80)	7342
-5	(-1,730.50)	91.5	-5	(-1453.50)	7346
-6	(-2,076.60)	91.3	-6	(-1744.20)	7349
-7	(-2,422.70)	91.1	-7	(-2034.90)	7353
-8	(-2,768.80)	90.9	-8	(-2325.60)	7357
-9	(-3,114.90)	90.7	-9	(-2616.30)	7360
-10	(-3,461.00)	90.5	-10	(-2907.00)	7364
	WEIGHTING FACTOR =	3.80		WEIGHTING FACTOR =	3.19

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	3,987.00 <- Fuel Sav/(Loss) 3,987.0	74.5 <- Adj. Act. EAF= 74.5	+10	1979.00	9754
+9	3,588.30	74.3	+9	1781.10	9766
+8	3,189.60	74.1	+8	1583.20	9778
+7	2,790.90	73.9	+7	1385.30	9790
+6	2,392.20	73.7	+6	1187.40	9802
+5	1,993.50	73.5	+5	989.50	9814
+4	1,594.80	73.3	+4	791.60	9825
+3	1,196.10	73.1	+3	593.70	9837
+2	797.40	72.9	+2	395.80	9849
+1	398.70	72.7	+1	197.90	9861
				0.00	9873
0	0.00	72.5	0	0.00 <- Fuel Sav/(Loss) 0	9948 <- Adj. Act. HR=10011
				(0.00)	10023
-1	(-398.70)	72.3	-1	(-197.90)	10035
-2	(-797.40)	72.1	-2	(-395.80)	10047
-3	(-1,196.10)	71.9	-3	(-593.70)	10059
-4	(-1,594.80)	71.7	-4	(-791.60)	10071
-5	(-1,993.50)	71.5	-5	(-989.50)	10083
-6	(-2,392.20)	71.3	-6	(-1187.40)	10094
-7	(-2,790.90)	71.1	-7	(-1385.30)	10106
-8	(-3,189.60)	70.9	-8	(-1583.20)	10118
-9	(-3,588.30)	70.7	-9	(-1781.10)	10130
-10	(-3,987.00)	70.5	-10	(-1979.00)	10142
	WEIGHTING FACTOR =	4.38		WEIGHTING FACTOR =	2.17

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	8,679.0 <- Fuel Sav/(Loss) 8,679.0	71.7 <- Adj. Act. EAF= 72.5	+10	1997.0 <- Fuel Sav/(Loss) 1,997.0	10695
+9	7,811.1	71.4	+9	1797.3	10695
+8	6,943.2	71.1	+8	1597.6	10695
+7	6,075.3	70.8	+7	1397.9	10695
+6	5,207.4	70.5	+6	1198.2	10695
+5	4,339.5	70.2	+5	998.5	10696
+4	3,471.6	69.9	+4	798.8	10696
+3	2,603.7	69.6	+3	599.1	10696
+2	1,735.8	69.3	+2	399.4	10696
+1	867.9	69.0	+1	199.7	10696
				0.0	10696 <- Adj. Act. HR=10705
0	0.0	68.7	0	0.0	10771
				(0.0)	10846
-1	(-867.9)	68.4	-1	(-199.7)	10846
-2	(-1,735.8)	68.1	-2	(-399.4)	10846
-3	(-2,603.7)	67.8	-3	(-599.1)	10846
-4	(-3,471.6)	67.5	-4	(-798.8)	10846
-5	(-4,339.5)	67.2	-5	(-998.5)	10847
-6	(-5,207.4)	66.9	-6	(-1198.2)	10847
-7	(-6,075.3)	66.6	-7	(-1397.9)	10847
-8	(-6,943.2)	66.3	-8	(-1597.6)	10847
-9	(-7,811.1)	66.0	-9	(-1797.3)	10847
-10	(-8,679.0)	65.7	-10	(-1997.0)	10847
	WEIGHTING FACTOR =	9.53		WEIGHTING FACTOR =	2.19

St. Lucie 1 heat rate fuel savings represent the savings from actual, unadjusted heat rate performance.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	4,849.00 <- Fuel Sav/(Loss) 4,849.0	63.1 <- Adj. Act. EAF= 66.9	+10	1793.00 <- Fuel Sav/(Loss) 1,793.0	10527
+9	4,364.10	62.8	+9	1613.70	10539
+8	3,879.20	62.5	+8	1434.40	10551
+7	3,394.30	62.2	+7	1255.10	10564
+6	2,909.40	61.9	+6	1075.80	10576
+5	2,424.50	61.6	+5	896.50	10588
+4	1,939.60	61.3	+4	717.20	10600
+3	1,454.70	61.0	+3	537.90	10612
+2	969.80	60.7	+2	358.60	10625
+1	484.90	60.4	+1	179.30	10637 <- Adj. Act. HR=10643
				0.00	10649
0	0.00	60.1	0	0.00	10724
				(0.00)	10799
-1	(-484.90)	59.8	-1	(-179.30)	10811
-2	(-969.80)	59.5	-2	(-358.60)	10823
-3	(-1,454.70)	59.2	-3	(-537.90)	10836
-4	(-1,939.60)	58.9	-4	(-717.20)	10848
-5	(-2,424.50)	58.6	-5	(-896.50)	10860
-6	(-2,909.40)	58.3	-6	(-1075.80)	10872
-7	(-3,394.30)	58.0	-7	(-1255.10)	10884
-8	(-3,879.20)	57.7	-8	(-1434.40)	10897
-9	(-4,364.10)	57.4	-9	(-1613.70)	10909
-10	(-4,849.00)	57.1	-10	(-1793.00)	10921
	WEIGHTING FACTOR =	5.32		WEIGHTING FACTOR =	1.97

St. Lucie 2 heat rate fuel savings represent the savings from actual, unadjusted heat rate performance.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,488.00	<- Fuel Sav/(Loss) 5,488.0	52.9	<- Adj. Act. EAF= 55.0	+10	2307.00	<- Fuel Sav/(Loss) 2,307.0	10732	
+9	4,939.20		52.6		+9	2076.30		10739	
+8	4,390.40		52.3		+8	1845.60		10746	
+7	3,841.60		52.0		+7	1614.90		10752	
+6	3,292.80		51.7		+6	1384.20		10759	
+5	2,744.00		51.4		+5	1153.50		10766	
+4	2,195.20		51.1		+4	922.80		10773	
+3	1,646.40		50.8		+3	692.10		10780	
+2	1,097.60		50.5		+2	461.40		10786	
+1	548.80		50.2		+1	230.70		10793	<- Adj. Act. HR=10797
						0.00		10800	
0	0.00		49.9		0	0.00		10875	
						(0.00)		10950	
-1	(-548.80)		49.6		-1	(-230.70)		10957	
-2	(-1,097.60)		49.3		-2	(-461.40)		10964	
-3	(-1,646.40)		49.0		-3	(-692.10)		10970	
-4	(-2,195.20)		48.7		-4	(-922.80)		10977	
-5	(-2,744.00)		48.4		-5	(-1153.50)		10984	
-6	(-3,292.80)		48.1		-6	(-1384.20)		10991	
-7	(-3,841.60)		47.8		-7	(-1614.90)		10998	
-8	(-4,390.40)		47.5		-8	(-1845.60)		11004	
-9	(-4,939.20)		47.2		-9	(-2076.30)		11011	
-10	(-5,488.00)		46.9		-10	(-2307.00)		11018	
	WEIGHTING FACTOR =		6.03			WEIGHTING FACTOR =		2.53	

Turkey Point 3 heat rate fuel savings represent the savings from actual, unadjusted heat rate performance.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	6,889.00 <- Fuel Sav/(Loss) 6,889.0	81.0 <- Adj. Act. EAF= 84.4	+10	4094.00	11061
+9	6,200.10	80.7	+9	3684.60	11074
+8	5,511.20	80.4	+8	3275.20	11086
+7	4,822.30	80.1	+7	2865.80	11099
+6	4,133.40	79.8	+6	2456.40	11112
+5	3,444.50	79.5	+5	2047.00	11125
+4	2,755.60	79.2	+4	1637.60	11137
+3	2,066.70	78.9	+3	1228.20	11150
+2	1,377.80	78.6	+2	818.80	11163
+1	688.90	78.3	+1	409.40	11175
				0.00	11188
0	0.00	78.0	0	0.00 <- Fuel Sav/(Loss) 0	11263 <- Adj. Act. HR=11304
				(0.00)	11338
-1	(-688.90)	77.7	-1	(-409.40)	11351
-2	(-1,377.80)	77.4	-2	(-818.80)	11363
-3	(-2,066.70)	77.1	-3	(-1228.20)	11376
-4	(-2,755.60)	76.8	-4	(-1637.60)	11389
-5	(-3,444.50)	76.5	-5	(-2047.00)	11402
-6	(-4,133.40)	76.2	-6	(-2456.40)	11414
-7	(-4,822.30)	75.9	-7	(-2865.80)	11427
-8	(-5,511.20)	75.6	-8	(-3275.20)	11440
-9	(-6,200.10)	75.3	-9	(-3684.60)	11452
-10	(-6,889.00)	75.0	-10	(-4094.00)	11465
	WEIGHTING FACTOR =	7.56		WEIGHTING FACTOR =	4.50

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2012

UNIT: Turkey Point 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	5,123.00	95.1	+10	5012.00	6791
+9	4,610.70	94.9	+9	4510.80	6798
+8	4,098.40	94.6	+8	4009.60	6805
+7	3,586.10	94.4	+7	3508.40	6812
+6	3,073.80	94.1	+6	3007.20	6819
+5	2,561.50	93.9	+5	2506.00	6826
+4	2,049.20	93.6	+4	2004.80	6833
+3	1,536.90	93.4	+3	1503.60	6840
+2	1,024.60	93.1	+2	1002.40	6847
+1	512.30	92.9	+1	501.20	6854
				0.00	6861
0	0.00 <- Fuel Sav/(Loss) 409.8	92.6 <- Adj. Act. EAF= 92.8	0	0.00 <- Fuel Sav/(Loss) 0	6936 <- Adj. Act. HR=6942
				(0.00)	7011
-1	(-512.30	92.4	-1	(-501.20)	7018
-2	(-1,024.60)	92.1	-2	(-1002.40)	7025
-3	(-1,536.90)	91.9	-3	(-1503.60)	7032
-4	(-2,049.20)	91.6	-4	(-2004.80)	7039
-5	(-2,561.50)	91.4	-5	(-2506.00)	7046
-6	(-3,073.80)	91.1	-6	(-3007.20)	7053
-7	(-3,586.10)	90.9	-7	(-3508.40)	7060
-8	(-4,098.40)	90.6	-8	(-4009.60)	7067
-9	(-4,610.70)	90.4	-9	(-4510.80)	7074
-10	(-5,123.00)	90.1	-10	(-5012.00)	7081
	WEIGHTING FACTOR =	5.62		WEIGHTING FACTOR =	5.50

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2012

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Ft. Myers 2	10/21/12-10/28/12; 10/20/12-10/27/12	CT-2A HRSG outage; CT-2B HRSG outage
	12/10/12-12/16/12; 12/11/12-12/17/12	CT-2C HRSG outage; CT-2D HRSG outage
	10/29/12-11/05/12; 10/28/12-11/04/12	CT-2E HRSG outage; CT-2F HRSG outage
Martin 8	9/22/12-9/29/12; 10/22/12-11/21/12	CT-8A HRSG outage; CT-8B upgrade
Manatee 3	11/9/12-11/28/12; 11/28/12-12/11/12	CT-3C Main steam to cold reheat valve replacement; CT-3D HRSG outage
Sanford 4	11/28/12-12/14/12; 10/9/12-11/3/12	CT-4A planned outage; CT-4B Major overhaul
Scherer 4	3/2/12/-5/9/12	Boiler outage
St. Lucie 1	1/1/12-4/21/12	Refueling outage and EPU modifications
St. Lucie 2	8/5/12-11/23/12	Refueling outage and EPU modifications
Turkey Point 3	2/26/12-9/5/12	Refueling outage and EPU modifications
Turkey Point 4	11/5/12-12/31/12	Refueling outage and EPU modifications
Turkey Point 5	11/26/12-12/12/12	CT-5C Rainbow hardware removal / HRSG inspection

WITNESS: CHARLES R. ROTE

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2014

AUGUST 30, 2013

CRR-1
DOCKET NO. 130001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
Pages 1 - 30

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. Terry J. Keith - TJK-1 EXHIBIT 20
PARTY Florida Power & Light Co. (FPL) (Direct)
DESCRIPTION Charles R. Rote - CRR-1

EXHIBIT INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2014

EXHIBIT	PAGE NUMBER	TITLE
CRR-1	7.201.001	Exhibit Index
	7.201.002	Projected System Generation
	7.201.003	Units Used to Determine GPIF
	7.201.004	GPIF Reward/Penalty Table (Estimated)
	7.201.005	GPIF Calculation of Maximum Allowed Incentive Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Projected Unit Heat Rate Equations
	7.201.009	Derivation of Weighting Factors
	7.201.010 - 7.201.019	Estimated Unit Performance Data
	7.201.020 - 7.201.029	Unit FOF and MOF vs Time Graphs
	7.201.030	Planned Outages Schedule (Estimated)

Projected System Generation
January Through December, 2014

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
CCEC	1,355	8,585	10,136,010	97.6	9.0	9.0	257,700
WEST COUNTY 2	1,202	8,449	8,734,540	84.8	7.8	16.8	236,870
ST. LUCIE 1	1,003	8,760	8,456,480	98.4	7.5	24.3	58,350
MARTIN 8	1,147	8,464	8,123,960	88.3	7.2	31.5	223,010
WEST COUNTY 1	1,208	7,718	8,052,150	85.6	7.2	38.7	219,030
WEST COUNTY 3	1,207	7,777	7,951,400	87.7	7.1	45.7	216,420
FT. MYERS 2	1,435	6,296	7,600,320	89.5	6.8	52.5	216,960
ST. LUCIE 2	860	7,944	6,563,220	98.4	5.8	58.3	40,650
TURKEY POINT 4	843	7,896	6,389,950	98.8	5.7	64.0	45,450
TURKEY POINT 3	833	7,968	6,356,760	98.7	5.7	69.7	45,370
MANATEE 3	1,134	6,544	6,125,600	85.8	5.4	75.1	168,500
PRV5	1,344	4,950	5,735,960	95.6	5.1	80.2	145,810
TURKEY POINT 5	1,166	5,768	5,468,360	87.3	4.9	85.1	150,210
SCHERER 4	646	5,896	3,636,150	96.2	3.2	88.3	89,840
SANFORD 5	994	4,103	3,529,270	90.8	3.1	91.4	103,080
SANFORD 4	990	3,381	2,853,810	89.9	2.5	94.0	83,660
MARTIN 3	454	2,687	1,093,990	93.0	1.0	95.0	32,840
LAUDERDALE 5	442	2,165	850,640	91.6	0.8	95.7	27,260
MARTIN 4	453	2,032	808,410	91.0	0.7	96.4	24,340
PUTNAM 2	255	4,092	715,470	69.9	0.6	97.1	26,400
LAUDERDALE 4	442	1,790	693,690	90.3	0.6	97.7	22,250
PUTNAM 1	251	3,965	590,940	60.3	0.5	98.2	22,400
ST JOHNS 1O	128	8,568	565,960	52.0	0.5	98.7	22,190
ST JOHNS 2O	128	7,368	553,530	59.2	0.5	99.2	21,260
MARTIN 1	808	550	259,000	58.9	0.2	99.4	21,430
MANATEE 1	795	435	220,410	64.2	0.2	99.6	22,940
FORT MYERS 3A_B	314	701	199,740	96.3	0.2	99.8	8,810
TURKEY POINT 1	380	477	103,710	57.4	0.1	99.9	10,750
MANATEE 2	795	148	84,290	72.2	0.1	100.0	8,600
MARTIN 2	808	72	15,630	27.1	0.0	100.0	1,270
LAUDERDALE 1-24	886	34	12,970	45.4	0.0	100.0	1,210
FORT MYERS 1-12	690	29	4,420	23.5	0.0	100.0	1,690
EVERGLADES 1-12	443	-	-	-	0.0	100.0	-
Total	**25,836**		**112,486,740**		**100.0**		**2,576,550**

UNITS TO BE USED TO DETERMINE THE GENERATING PERFORMANCE INCENTIVE FACTOR

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2014

Ft. Myers 2

Manatee 3

Martin 8

St. Lucie 1

St. Lucie 2

Turkey Point 3

Turkey Point 4

Turkey Point 5

West County 1

West County 2

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2014

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	110,700	52,334
+ 9	99,630	47,101
+ 8	88,560	41,867
+ 7	77,490	36,634
+ 6	66,420	31,400
+ 5	55,350	26,167
+ 4	44,280	20,934
+ 3	33,210	15,700
+ 2	22,140	10,467
+ 1	11,070	5,233
0	0	0
- 1	(11,070)	(5,233)
- 2	(22,140)	(10,467)
- 3	(33,210)	(15,700)
- 4	(44,280)	(20,934)
- 5	(55,350)	(26,167)
- 6	(66,420)	(31,400)
- 7	(77,490)	(36,634)
- 8	(88,560)	(41,867)
- 9	(99,630)	(47,101)
- 10	(110,700)	(52,334)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	12,842,009,102	
LINE 2	MONTH OF JANUARY	2014	$	13,174,942,223	
LINE 3	MONTH OF FEBRUARY	2014	$	13,260,658,186	
LINE 4	MONTH OF MARCH	2014	$	13,371,150,032	
LINE 5	MONTH OF APRIL	2014	$	13,453,737,978	
LINE 6	MONTH OF MAY	2014	$	13,616,507,296	
LINE 7	MONTH OF JUNE	2014	$	13,421,094,159	
LINE 8	MONTH OF JULY	2014	$	13,598,488,691	
LINE 9	MONTH OF AUGUST	2014	$	13,781,938,714	
LINE 10	MONTH OF SEPTEMBER	2014	$	13,427,755,445	
LINE 11	MONTH OF OCTOBER	2014	$	13,522,932,731	
LINE 12	MONTH OF NOVEMBER	2014	$	13,632,990,772	
LINE 13	MONTH OF DECEMBER	2014	$	13,715,190,715	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	13,447,645,850	
LINE 15	25 BASIS POINTS			0.0025	
LINE 16	REVENUE EXPANSION FACTOR			61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	54,771,386	
LINE 18	JURISDICTIONAL SALES			105,843,225,122	KWH
LINE 19	TOTAL SALES			110,767,695,190	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			95.55%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	52,334,059	

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	3.57	95.0	97.5	92.5	3,948	-3,948
Martin 8	3.36	92.4	94.9	89.9	3,714	-3,714
Manatee 3	2.95	82.8	85.8	79.8	3,271	-3,271
St. Lucie 1	9.71	90.8	94.3	87.3	10,750	-10,750
St. Lucie 2	6.67	83.4	86.4	80.4	7,383	-7,383
Turkey Point 3	7.31	81.1	84.6	77.6	8,093	-8,093
Turkey Point 4	6.16	83.7	86.7	80.7	6,823	-6,823
Turkey Point 5	2.81	78.0	80.5	75.5	3,116	-3,116
West County 1	3.81	79.2	82.2	76.2	4,213	-4,213
West County 2	3.98	86.2	89.2	83.2	4,409	-4,409
	50.33				55,720	-55,720

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Ft. Myers 2	2.61	7,200	89.5	7,104	7,296	2,893	-2,893
Martin 8	5.07	6,911	88.3	6,737	7,085	5,615	-5,615
Manatee 3	3.96	6,961	85.8	6,780	7,142	4,381	-4,381
St. Lucie 1	9.77	10,703	98.4	10,334	11,072	10,810	-10,810
St. Lucie 2	7.34	10,556	98.4	10,213	10,899	8,128	-8,128
Turkey Point 3	5.24	11,025	98.7	10,747	11,303	5,803	-5,803
Turkey Point 4	3.88	11,138	98.8	10,929	11,347	4,294	-4,294
Turkey Point 5	2.85	7,055	87.3	6,907	7,203	3,151	-3,151
West County 1	4.14	6,842	85.6	6,699	6,985	4,578	-4,578
West County 2	4.81	6,848	84.8	6,694	7,002	5,327	-5,327
	49.67					54,980	-54,980

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

				ANOHR Equation					
Plant/Unit	**ANOHR**	**NOF**	**MW**	**a coef.**	**b coef.**	**Bounds**	**First**	**Last**	**Exclusions**
Ft. Myers 2	7,200	89.5	1435	7837	-7.12	96	07-10	06-13	4/11, 5/11, 6/11
Martin 8	6,911	88.3	1147	7527	-6.98	174	07-10	06-13	7/10-12/10
Manatee 3	6,961	85.8	1134	7237	-3.22	181	07-10	06-13	9/11, 11/11
St. Lucie 1	10,703	98.4	1003	15894	-52.75	369	07-10	06-13	7/10-8/10, 10/11-5/12
St. Lucie 2	10,556	98.4	860	13424	-29.15	343	07-10	06-13	1/11-4/11, 7/12-12/12
Turkey Point 3	11,025	98.7	833	12661	-16.58	278	07-10	06-13	10/10, 10/11, 3/12-10/12, 5/13
Turkey Point 4	11,138	98.8	843	15269	-41.81	209	07-10	06-13	4/11, 11/12-5/13
Turkey Point 5	7,055	87.3	1166	7528	-5.42	148	07-10	06-13	None
West County 1	6,842	85.6	1208	7324	-5.63	143	07-10	06-13	9/10, 6/13
West County 2	6,848	84.8	1202	7497	-7.65	154	07-10	06-13	12/10, 8/12

DERIVATION OF WEIGHTING FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2014

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Ft. Myers 2	EAF	2,576,550	2,572,602	3,948	3.57
Ft. Myers 2	ANOHR	2,576,550	2,573,657	2,893	2.61
Martin 8	EAF	2,576,550	2,572,836	3,714	3.36
Martin 8	ANOHR	2,576,550	2,570,935	5,615	5.07
Manatee 3	EAF	2,576,550	2,573,279	3,271	2.95
Manatee 3	ANOHR	2,576,550	2,572,169	4,381	3.96
St. Lucie 1	EAF	2,576,550	2,565,800	10,750	9.71
St. Lucie 1	ANOHR	2,576,550	2,565,740	10,810	9.77
St. Lucie 2	EAF	2,576,550	2,569,167	7,383	6.67
St. Lucie 2	ANOHR	2,576,550	2,568,422	8,128	7.34
Turkey Point 3	EAF	2,576,550	2,568,457	8,093	7.31
Turkey Point 3	ANOHR	2,576,550	2,570,747	5,803	5.24
Turkey Point 4	EAF	2,576,550	2,569,727	6,823	6.16
Turkey Point 4	ANOHR	2,576,550	2,572,256	4,294	3.88
Turkey Point 5	EAF	2,576,550	2,573,434	3,116	2.81
Turkey Point 5	ANOHR	2,576,550	2,573,399	3,151	2.85
West County 1	EAF	2,576,550	2,572,337	4,213	3.81
West County 1	ANOHR	2,576,550	2,571,972	4,578	4.14
West County 2	EAF	2,576,550	2,572,141	4,409	3.98
West County 2	ANOHR	2,576,550	2,571,223	5,327	4.81
TOTAL				110,700	100.00

(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET
(2) ALL OTHER UNITS PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	Ft. Myers 2	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	95.0	95.0	95.0	95.0	95.0	95.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	5.0	5.0	5.0	5.0	5.0	5.0
4	EUOR (%)	8.3	6.2	5.0	5.8	6.2	5.8
5	PH	744	672	744	720	744	720
6	SH	450	546	744	617	604	625
7	RSH	294	126	0	103	140	95
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	13	15	14	15	14
11	MOH & EMOH	22	20	22	22	22	22
12	Oper Mbtu	3,917,473	4,608,916	6,423,387	5,143,250	5,369,688	5,546,392
13	Net Gen (MWH)	544,169	638,354	891,518	711,573	747,451	771,833
14	ANOHR (Btu/KWH)	7,199	7,220	7,205	7,228	7,184	7,186
15	NOF (%)	89.6	86.7	88.8	85.5	91.7	91.5
16	NSC (MW)	1349	1349	1349	1349	1349	1349
17	ANOHR Equation	-7.12 x NOF + 7837					

	Ft. Myers 2	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	95.0	95.0	95.0	95.0	95.0	95.0	95.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	5.0	5.0	5.0	5.0	5.0	5.0	5.0
4	EUOR (%)	6.5	7.5	7.9	5.6	14.3	13.9	7.0
5	PH	744	744	720	744	720	744	8,760
6	SH	574	497	455	664	252	268	6,296
7	RSH	170	247	265	80	468	476	2464
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	14	15	14	15	175
11	MOH & EMOH	22	22	22	22	22	22	263
12	Oper Mbtu	5,198,946	4,590,946	4,189,678	5,824,848	1,508,687	2,373,090	54,722,304
13	Net Gen (MWH)	724,996	641,552	585,314	809,794	203,574	330,192	7,600,320
14	ANOHR (Btu/KWH)	7,171	7,156	7,158	7,193	7,411	7,187	7,200
15	NOF (%)	93.6	95.7	95.4	90.4	59.9	91.3	89.5
16	NSC (MW)	1349	1349	1349	1349	1349	1349	1349
17	ANOHR Equation	-7.12 x NOF + 7837						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	Manatee 3	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	91.1	91.1	91.1	91.1	77.9	28.9
2	EPOF (%)	0.0	0.0	0.0	0.0	14.5	68.3
3	EUOF (%)	8.9	8.9	8.9	8.9	7.6	2.8
4	EUOR (%)	14.9	10.7	9.4	9.9	9.8	7.8
5	PH	744	672	744	720	744	720
6	SH	444	557	703	648	579	260
7	RSH	300	115	41	72	117	52
8	UH	0	0	0	0	48	408
9	POH	0	0	0	0	48	408
10	FOH & EFOH	16	15	16	16	14	5
11	MOH & EMOH	50	45	50	48	43	15
12	Oper Mbtu	3,080,860	3,651,874	4,567,274	4,254,601	3,665,283	1,333,477
13	Net Gen (MWH)	443,800	524,770	656,029	611,469	525,941	189,927
14	ANOHR (Btu/KWH)	6,942	6,959	6,962	6,958	6,969	7,021
15	NOF (%)	91.6	86.4	85.5	86.5	83.3	67.0
16	NSC (MW)	1091	1091	1091	1091	1091	1091
17	ANOHR Equation	-3.22 x NOF + 7237					

	Manatee 3	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	70.5	87.5	91.1	91.1	91.1	91.1	82.8
2	EPOF (%)	22.6	4.0	0.0	0.0	0.0	0.0	9.1
3	EUOF (%)	6.9	8.5	8.9	8.9	8.9	8.9	8.1
4	EUOR (%)	9.0	9.3	11.9	10.1	13.9	14.9	10.8
5	PH	744	744	720	744	720	744	8,760
6	SH	569	682	540	657	460	445	6,544
7	RSH	175	62	180	87	260	299	1760
8	UH	0	0	0	0	0	0	456
9	POH	0	0	0	0	0	0	456
10	FOH & EFOH	13	16	16	16	16	16	175
11	MOH & EMOH	39	48	48	50	48	50	534
12	Oper Mbtu	3,101,137	4,435,326	3,732,335	4,499,119	3,265,199	3,041,355	42,640,302
13	Net Gen (MWH)	442,577	637,168	537,568	647,728	470,829	437,794	6,125,600
14	ANOHR (Btu/KWH)	7,007	6,961	6,943	6,946	6,935	6,947	6,961
15	NOF (%)	71.3	85.6	91.2	90.4	93.8	90.2	85.8
16	NSC (MW)	1091	1091	1091	1091	1091	1091	1091
17	ANOHR Equation	-3.22 x NOF + 7237						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	Martin 8	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	94.2	88.3	78.3	94.2	94.2	94.2
2	EPOF (%)	0.0	6.3	16.9	0.0	0.0	0.0
3	EUOF (%)	5.8	5.4	4.8	5.8	5.8	5.8
4	EUOR (%)	6.0	5.5	5.0	5.8	5.8	5.8
5	PH	744	672	744	720	744	720
6	SH	718	664	716	720	744	720
7	RSH	26	8	28	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	13	13	15	15	15
11	MOH & EMOH	28	24	23	27	28	27
12	Oper Mbtu	4,816,927	4,232,756	4,276,873	4,632,840	5,046,616	4,889,265
13	Net Gen (MWH)	697,802	610,259	612,996	668,423	731,924	709,103
14	ANOHR (Btu/KWH)	6,903	6,936	6,977	6,931	6,895	6,895
15	NOF (%)	89.4	84.6	78.8	85.4	90.5	90.6
16	NSC (MW)	1087	1087	1087	1087	1087	1087
17	ANOHR Equation	-6.98 x NOF + 7527					

	Martin 8	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	94.2	94.2	94.2	94.2	94.2	94.2	92.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	1.9
3	EUOF (%)	5.8	5.8	5.8	5.8	5.8	5.8	5.7
4	EUOR (%)	5.9	5.8	6.0	5.9	6.3	7.1	5.9
5	PH	744	744	720	744	720	744	8,760
6	SH	736	744	697	734	661	610	8,464
7	RSH	8	0	23	10	59	134	296
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	28	28	27	28	27	28	324
12	Oper Mbtu	5,018,623	5,063,956	4,760,604	5,012,372	4,326,086	4,055,818	56,144,688
13	Net Gen (MWH)	728,181	734,652	690,944	727,485	625,157	587,034	8,123,960
14	ANOHR (Btu/KWH)	6,892	6,893	6,890	6,890	6,920	6,909	6,911
15	NOF (%)	91.0	90.8	91.2	91.2	87.0	88.5	88.3
16	NSC (MW)	1087	1087	1087	1087	1087	1087	1087
17	ANOHR Equation	-6.98 x NOF + 7527						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	St. Lucie 1	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	90.8	90.8	90.8	90.8	90.8	90.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	9.2	9.2	9.2	9.2	9.2	9.2
4	EUOR (%)	9.2	9.2	9.2	9.2	9.2	9.2
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	45	40	45	43	45	43
11	MOH & EMOH	24	21	24	23	24	23
12	Oper Mbtu	7,737,760	6,988,960	7,737,760	7,403,848	7,650,648	7,403,848
13	Net Gen (MWH)	727,575	657,166	727,575	688,666	711,622	688,666
14	ANOHR (Btu/KWH)	10,635	10,635	10,635	10,751	10,751	10,751
15	NOF (%)	99.7	99.7	99.7	97.5	97.5	97.5
16	NSC (MW)	981	981	981	981	981	981
17	ANOHR Equation	-52.75 x NOF + 15894					

	St. Lucie 1	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	90.8	90.8	90.8	90.8	90.8	90.8	90.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	9.2	9.2	9.2	9.2	9.2	9.2	9.2
4	EUOR (%)	9.2	9.2	9.2	9.2	9.2	9.2	9.2
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	45	45	43	45	43	45	526
11	MOH & EMOH	24	24	23	24	23	24	280
12	Oper Mbtu	7,650,648	7,650,648	7,403,848	7,650,648	7,488,146	7,737,749	90,509,705
13	Net Gen (MWH)	711,622	711,622	688,666	711,622	704,104	727,574	8,456,480
14	ANOHR (Btu/KWH)	10,751	10,751	10,751	10,751	10,635	10,635	10,703
15	NOF (%)	97.5	97.5	97.5	97.5	99.7	99.7	98.4
16	NSC (MW)	981	981	981	981	981	981	981
17	ANOHR Equation	-52.75 x NOF + 15894						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	St. Lucie 2	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	92.0	92.0	6.0	76.6	92.0	92.0
2	EPOF (%)	0.0	0.0	93.5	16.7	0.0	0.0
3	EUOF (%)	8.0	8.0	0.5	6.7	8.0	8.0
4	EUOR (%)	8.0	8.0	8.0	8.0	8.0	8.0
5	PH	744	672	744	720	744	720
6	SH	744	672	48	600	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	696	120	0	0
9	POH	0	0	696	120	0	0
10	FOH & EFOH	34	30	2	27	34	33
11	MOH & EMOH	26	24	2	21	26	25
12	Oper Mbtu	6,559,730	5,924,919	423,208	5,200,005	6,447,962	6,239,973
13	Net Gen (MWH)	623,845	563,473	40,248	491,401	609,333	589,678
14	ANOHR (Btu/KWH)	10,515	10,515	10,515	10,582	10,582	10,582
15	NOF (%)	99.8	99.8	99.8	97.5	97.5	97.5
16	NSC (MW)	840	840	840	840	840	840
17	ANOHR Equation	-29.15 x NOF + 13424					

	St. Lucie 2	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	92.0	92.0	92.0	92.0	92.0	92.0	83.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.3
3	EUOF (%)	8.0	8.0	8.0	8.0	8.0	8.0	7.3
4	EUOR (%)	8.0	8.0	8.0	8.0	8.0	8.0	8.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,944
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	816
9	POH	0	0	0	0	0	0	816
10	FOH & EFOH	34	34	33	34	33	34	359
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	6,447,962	6,447,962	6,239,973	6,447,962	6,348,126	6,559,720	69,281,350
13	Net Gen (MWH)	609,333	609,333	589,678	609,333	603,721	623,844	6,563,220
14	ANOHR (Btu/KWH)	10,582	10,582	10,582	10,582	10,515	10,515	10,556
15	NOF (%)	97.5	97.5	97.5	97.5	99.8	99.8	98.4
16	NSC (MW)	840	840	840	840	840	840	840
17	ANOHR Equation	-29.15 x NOF + 13424						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	Turkey Point 3	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	89.1	89.1	46.0	35.6	89.1	89.1
2	EPOF (%)	0.0	0.0	48.4	60.0	0.0	0.0
3	EUOF (%)	10.9	10.9	5.6	4.4	10.9	10.9
4	EUOR (%)	10.9	10.9	10.9	10.9	10.9	10.9
5	PH	744	672	744	720	744	720
6	SH	744	672	384	288	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	360	432	0	0
9	POH	0	0	360	432	0	0
10	FOH & EFOH	55	50	28	21	55	53
11	MOH & EMOH	26	24	13	10	26	25
12	Oper Mbtu	6,643,817	6,000,851	3,429,077	2,505,729	6,473,165	6,264,356
13	Net Gen (MWH)	604,258	545,780	311,876	226,886	586,125	567,218
14	ANOHR (Btu/KWH)	10,995	10,995	10,995	11,044	11,044	11,044
15	NOF (%)	100.5	100.5	100.5	97.5	97.5	97.5
16	NSC (MW)	808	808	808	808	808	808
17	ANOHR Equation	-16.58 x NOF + 12661					

	Turkey Point 3	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	89.1	89.1	89.1	89.1	89.1	89.1	81.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.0
3	EUOF (%)	10.9	10.9	10.9	10.9	10.9	10.9	9.9
4	EUOR (%)	10.9	10.9	10.9	10.9	10.9	10.9	10.9
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,968
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	792
9	POH	0	0	0	0	0	0	792
10	FOH & EFOH	55	55	53	55	53	55	587
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	6,473,165	6,473,165	6,264,356	6,473,165	6,429,491	6,643,828	70,083,279
13	Net Gen (MWH)	586,125	586,125	567,218	586,125	584,765	604,259	6,356,760
14	ANOHR (Btu/KWH)	11,044	11,044	11,044	11,044	10,995	10,995	11,025
15	NOF (%)	97.5	97.5	97.5	97.5	100.5	100.5	98.7
16	NSC (MW)	808	808	808	808	808	808	808
17	ANOHR Equation	-16.58 x NOF + 12661						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	Turkey Point 4	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	92.9	92.9	92.9	92.9	92.9	92.9
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1
4	EUOR (%)	7.1	7.1	7.1	7.1	7.1	7.1
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	26	24	26	26	26	26
11	MOH & EMOH	26	24	26	26	26	26
12	Oper Mbtu	6,770,049	6,114,901	6,770,049	6,435,270	6,649,784	6,435,270
13	Net Gen (MWH)	611,512	552,335	611,512	574,937	594,102	574,937
14	ANOHR (Btu/KWH)	11,071	11,071	11,071	11,193	11,193	11,193
15	NOF (%)	100.4	100.4	100.4	97.5	97.5	97.5
16	NSC (MW)	819	819	819	819	819	819
17	ANOHR Equation	-41.81 x NOF + 15269					

	Turkey Point 4	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	92.9	92.9	71.3	6.0	92.9	92.9	83.7
2	EPOF (%)	0.0	0.0	23.3	93.5	0.0	0.0	9.9
3	EUOF (%)	7.1	7.1	5.4	0.5	7.1	7.1	6.4
4	EUOR (%)	7.1	7.1	7.1	7.1	7.1	7.1	7.1
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	552	48	720	744	7,896
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	168	696	0	0	864
9	POH	0	0	168	696	0	0	864
10	FOH & EFOH	26	26	20	2	26	26	280
11	MOH & EMOH	26	26	20	2	26	26	280
12	Oper Mbtu	6,649,784	6,649,784	4,933,707	429,028	6,551,652	6,770,038	71,171,263
13	Net Gen (MWH)	594,102	594,102	440,785	38,330	591,785	611,511	6,389,950
14	ANOHR (Btu/KWH)	11,193	11,193	11,193	11,193	11,071	11,071	11,138
15	NOF (%)	97.5	97.5	97.5	97.5	100.4	100.4	98.8
16	NSC (MW)	819	819	819	819	819	819	819
17	ANOHR Equation	-41.81 x NOF + 15269						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	Turkey Point 5	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	92.4	38.0	79.0	87.8	73.8	70.1
2	EPOF (%)	0.0	58.9	14.5	5.0	20.2	24.2
3	EUOF (%)	7.6	3.1	6.5	7.2	6.0	5.7
4	EUOR (%)	14.4	9.1	6.6	9.2	9.4	6.8
5	PH	744	672	744	720	744	720
6	SH	392	230	725	566	478	606
7	RSH	352	154	19	154	266	114
8	UH	0	288	0	0	0	0
9	POH	0	288	0	0	0	0
10	FOH & EFOH	18	7	15	16	14	13
11	MOH & EMOH	39	14	33	36	31	28
12	Oper Mbtu	2,733,544	1,146,448	4,393,006	3,792,604	2,939,196	3,433,352
13	Net Gen (MWH)	388,674	159,628	618,559	537,653	414,263	481,401
14	ANOHR (Btu/KWH)	7,033	7,182	7,102	7,054	7,095	7,132
15	NOF (%)	91.3	63.9	78.6	87.5	79.8	73.1
16	NSC (MW)	1086	1086	1086	1086	1086	1086
17	ANOHR Equation	-5.42 x NOF + 7528					

	Turkey Point 5	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	92.4	92.4	92.4	92.4	49.3	71.5	78.0
2	EPOF (%)	0.0	0.0	0.0	0.0	46.7	22.6	15.6
3	EUOF (%)	7.6	7.6	7.6	7.6	4.0	5.9	6.4
4	EUOR (%)	8.5	9.5	11.3	9.9	14.5	16.7	9.7
5	PH	744	744	720	744	720	744	8,760
6	SH	660	596	484	570	200	261	5,768
7	RSH	84	148	236	174	520	483	2704
8	UH	0	0	0	0	0	0	288
9	POH	0	0	0	0	0	0	288
10	FOH & EFOH	18	18	17	18	9	14	175
11	MOH & EMOH	39	39	38	39	20	30	385
12	Oper Mbtu	4,713,895	4,312,160	3,545,919	4,133,609	1,529,002	1,874,823	38,579,280
13	Net Gen (MWH)	671,495	614,881	506,126	589,505	218,992	267,183	5,468,360
14	ANOHR (Btu/KWH)	7,020	7,013	7,006	7,012	6,982	7,017	7,055
15	NOF (%)	93.7	95.0	96.3	95.2	100.8	94.3	87.3
16	NSC (MW)	1086	1086	1086	1086	1086	1086	1086
17	ANOHR Equation	-5.42 x NOF + 7528						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

	West County 1	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	89.4	89.4	89.4	89.4	89.4	89.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	10.6	10.6	10.6	10.6	10.6	10.6
4	EUOR (%)	11.1	10.7	10.6	10.6	10.6	10.6
5	PH	744	672	744	720	744	720
6	SH	710	664	744	720	744	720
7	RSH	34	8	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	17	15	17	16	17	16
11	MOH & EMOH	62	56	62	60	62	60
12	Oper Mbtu	5,141,649	4,784,330	5,478,923	5,034,344	5,472,315	5,264,946
13	Net Gen (MWH)	752,253	699,668	802,655	734,619	801,687	770,856
14	ANOHR (Btu/KWH)	6,835	6,838	6,826	6,853	6,826	6,830
15	NOF (%)	86.9	86.4	88.5	83.7	88.4	87.8
16	NSC (MW)	1219	1219	1219	1219	1219	1219
17	ANOHR Equation	-5.63 x NOF + 7324					

	West County 1	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	89.4	89.4	85.5	13.5	47.6	89.4	79.2
2	EPOF (%)	0.0	0.0	4.4	84.9	46.7	0.0	11.4
3	EUOF (%)	10.6	10.6	10.1	1.6	5.7	10.6	9.4
4	EUOR (%)	10.6	10.6	10.3	9.3	10.4	11.3	10.7
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	708	128	391	701	7,718
7	RSH	0	0	12	208	113	43	418
8	UH	0	0	0	408	216	0	624
9	POH	0	0	0	408	216	0	624
10	FOH & EFOH	17	17	16	3	9	17	175
11	MOH & EMOH	62	62	57	9	32	62	648
12	Oper Mbtu	5,497,749	5,507,601	5,048,457	306,582	2,353,225	5,167,371	55,092,810
13	Net Gen (MWH)	805,649	807,211	737,755	42,759	339,914	757,124	8,052,150
14	ANOHR (Btu/KWH)	6,824	6,823	6,843	7,170	6,923	6,825	6,842
15	NOF (%)	88.8	89.0	85.5	27.4	71.3	88.6	85.6
16	NSC (MW)	1219	1219	1219	1219	1219	1219	1219
17	ANOHR Equation	-5.63 x NOF + 7324						

ESTIMATED UNIT PERFORMANCE DATA

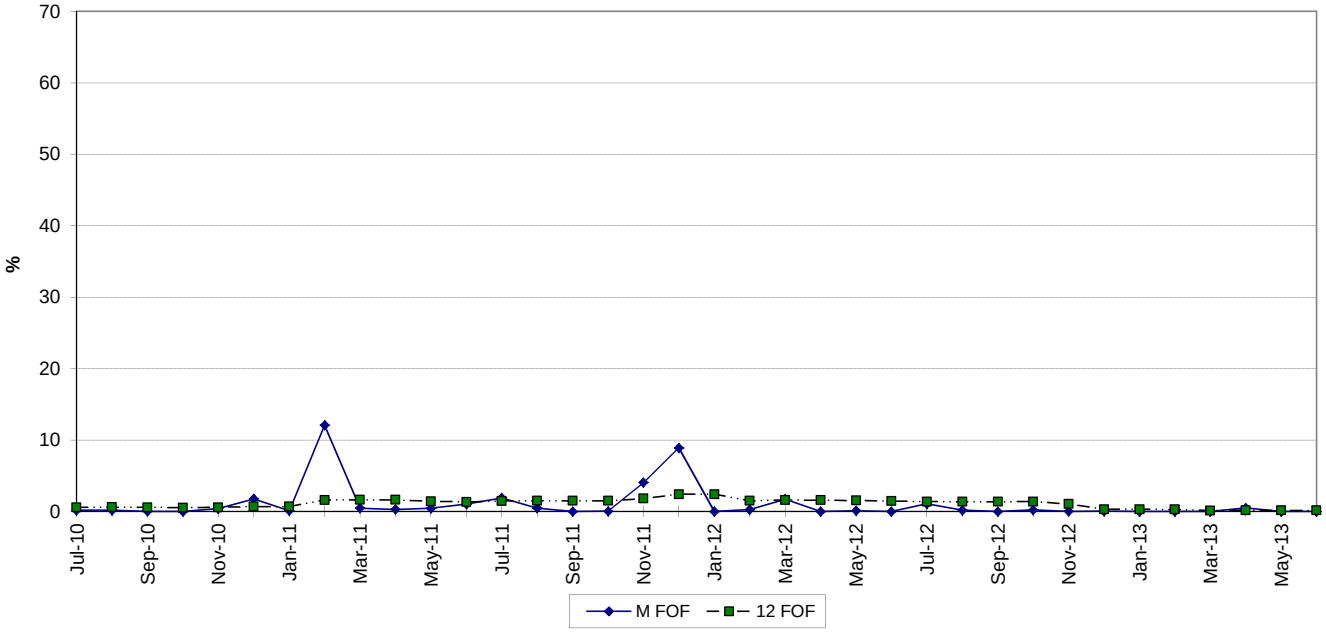
FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

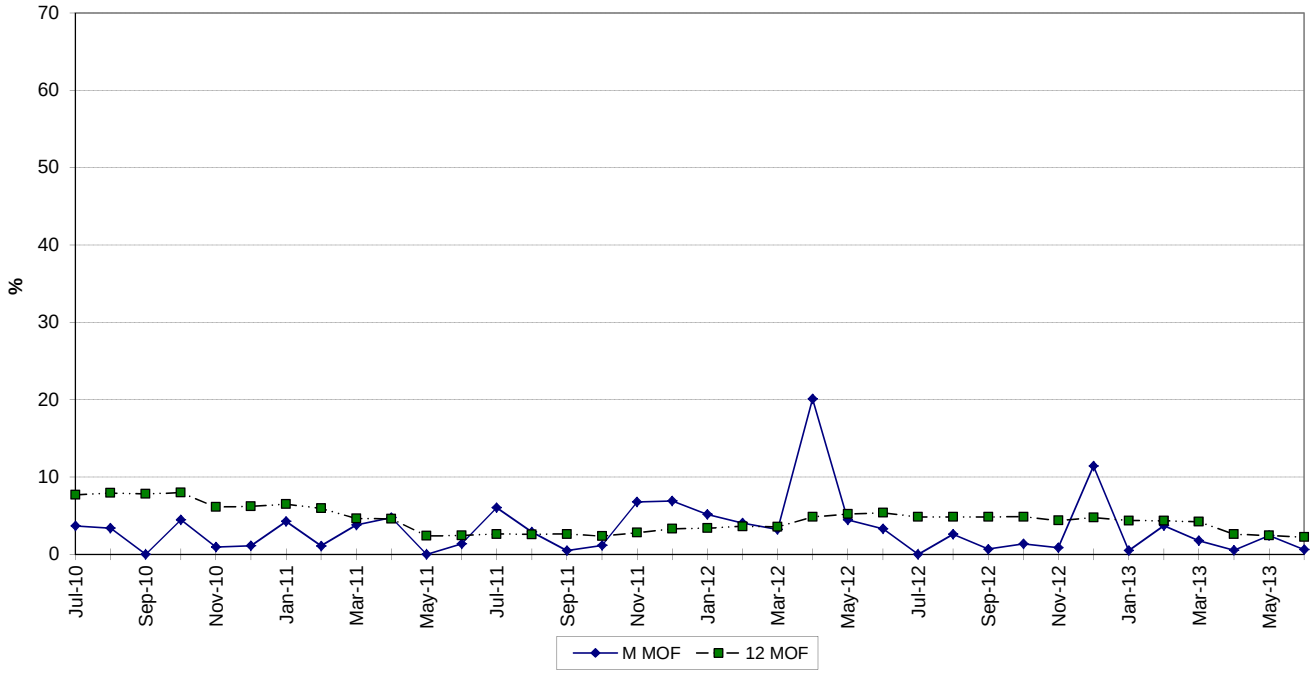
	West County 2	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14
1	EAF (%)	90.4	90.4	90.4	90.4	90.4	53.3
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	41.1
3	EUOF (%)	9.6	9.6	9.6	9.6	9.6	5.6
4	EUOR (%)	9.6	9.6	9.6	9.6	9.7	8.8
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	735	459
7	RSH	0	0	0	0	9	93
8	UH	0	0	0	0	0	168
9	POH	0	0	0	0	0	168
10	FOH & EFOH	16	14	16	15	16	9
11	MOH & EMOH	55	50	55	54	55	32
12	Oper Mbtu	5,329,078	4,790,278	5,368,496	5,053,454	5,378,984	2,904,794
13	Net Gen (MWH)	779,105	700,026	785,442	737,300	788,245	419,586
14	ANOHR (Btu/KWH)	6,840	6,843	6,835	6,854	6,824	6,923
15	NOF (%)	85.9	85.5	86.6	84.0	88.0	75.0
16	NSC (MW)	1219	1219	1219	1219	1219	1219
17	ANOHR Equation	-7.65 x NOF + 7497					

	West County 2	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1	EAF (%)	75.9	90.4	90.4	90.4	90.4	90.4	86.2
2	EPOF (%)	16.1	0.0	0.0	0.0	0.0	0.0	4.7
3	EUOF (%)	8.0	9.6	9.6	9.6	9.6	9.6	9.1
4	EUOR (%)	8.5	9.6	9.6	9.6	9.6	9.6	9.4
5	PH	744	744	720	744	720	744	8,760
6	SH	703	744	720	744	720	744	8,449
7	RSH	41	0	0	0	0	0	143
8	UH	0	0	0	0	0	0	168
9	POH	0	0	0	0	0	0	168
10	FOH & EFOH	13	16	15	16	15	16	175
11	MOH & EMOH	47	55	54	55	54	55	622
12	Oper Mbtu	4,534,238	5,462,880	5,289,467	5,447,449	5,015,168	5,230,644	59,814,130
13	Net Gen (MWH)	656,090	800,774	775,468	798,278	731,074	763,152	8,734,540
14	ANOHR (Btu/KWH)	6,911	6,822	6,821	6,824	6,860	6,854	6,848
15	NOF (%)	76.6	88.3	88.4	88.0	83.3	84.1	84.8
16	NSC (MW)	1219	1219	1219	1219	1219	1219	1219
17	ANOHR Equation	-7.65 x NOF + 7497						

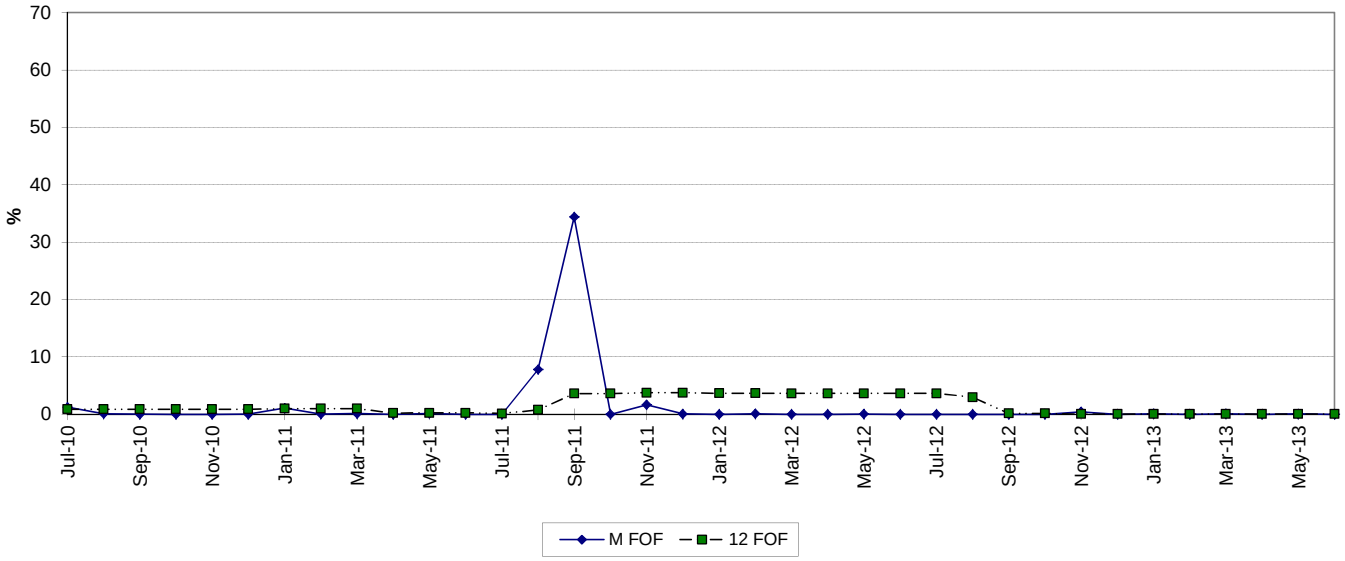
FT. MYERS 2
FORCED OUTAGE FACTOR



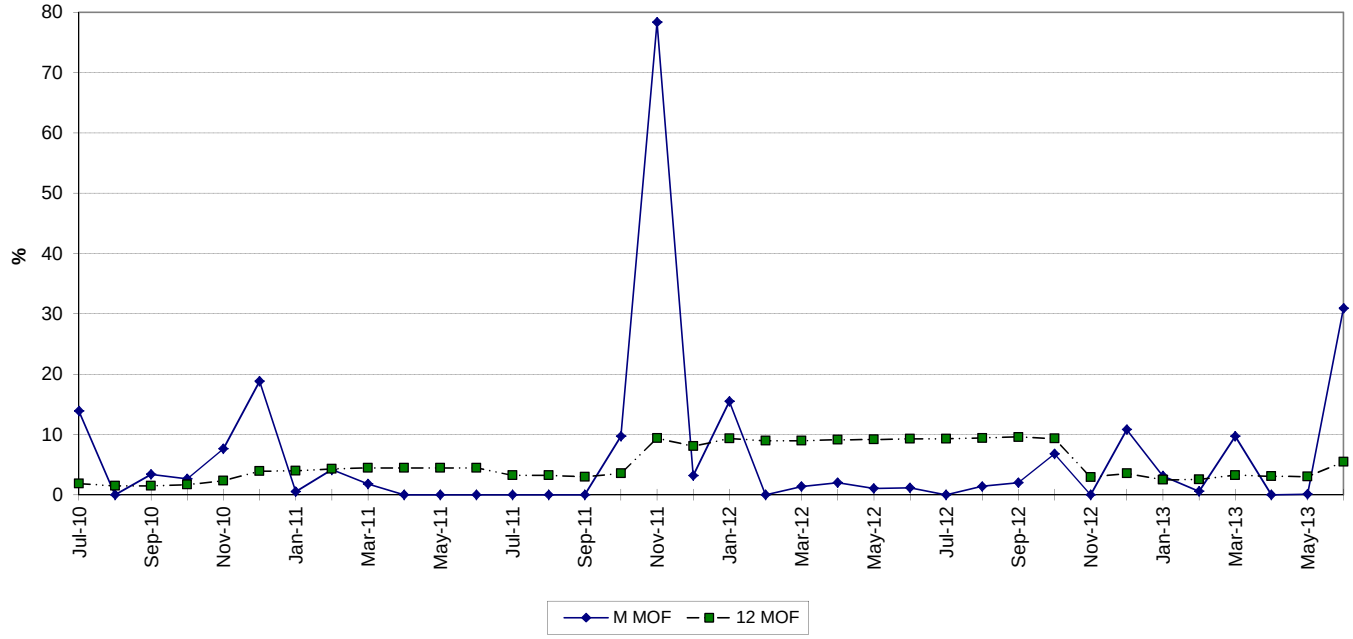
MAINTENANCE OUTAGE FACTOR



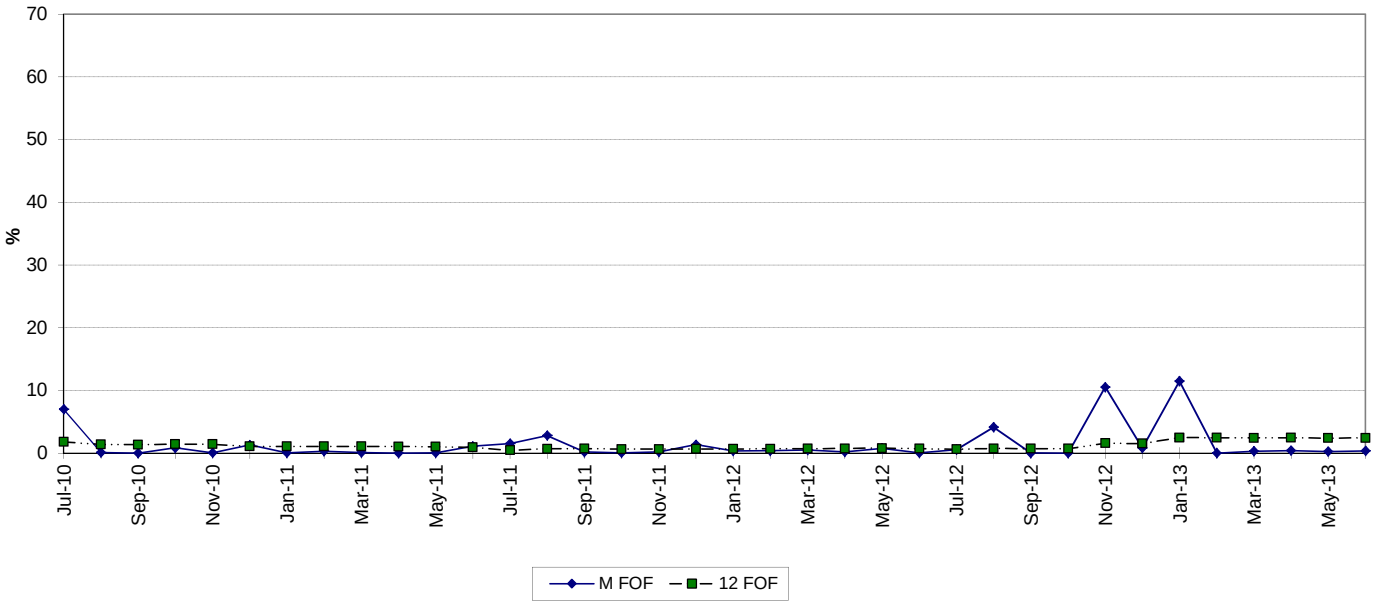
MANATEE 3
FORCED OUTAGE FACTOR



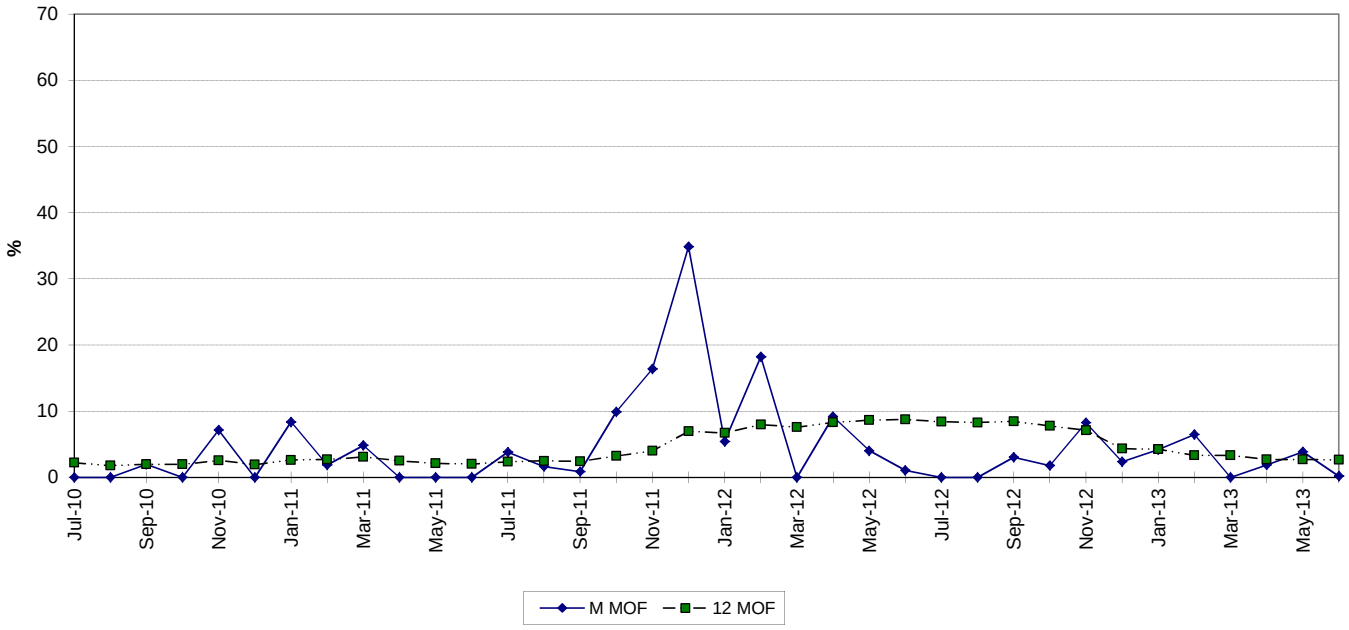
MAINTENANCE OUTAGE FACTOR



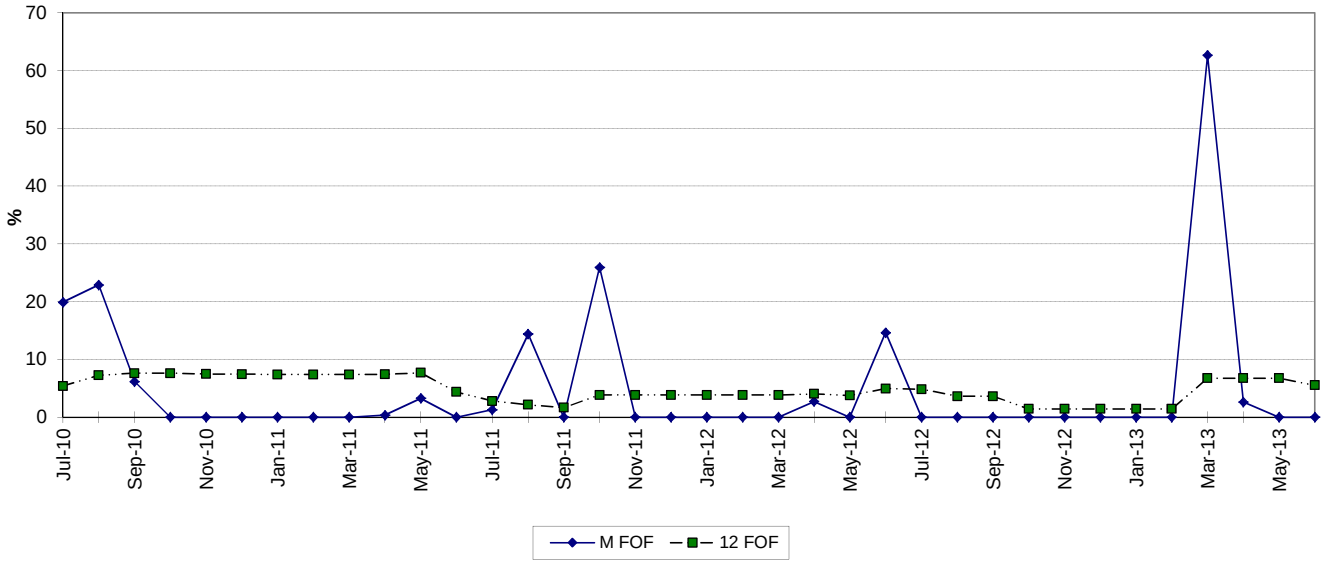
MARTIN 8
FORCED OUTAGE FACTOR



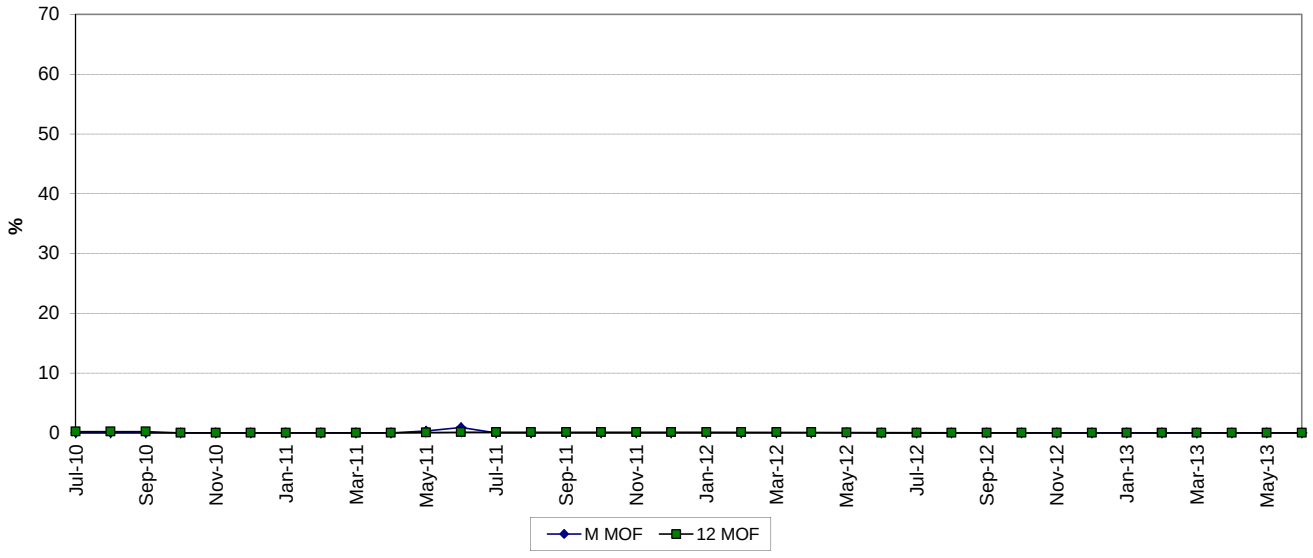
MAINTENANCE OUTAGE FACTOR



ST. LUCIE 1
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



ST. LUCIE 2
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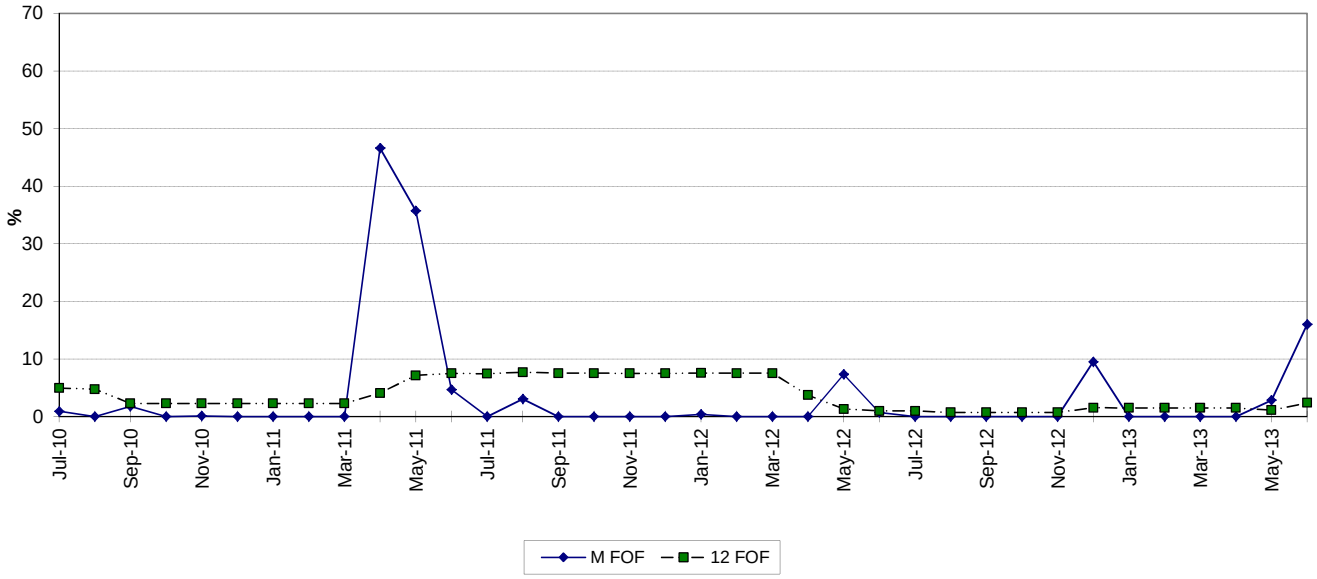
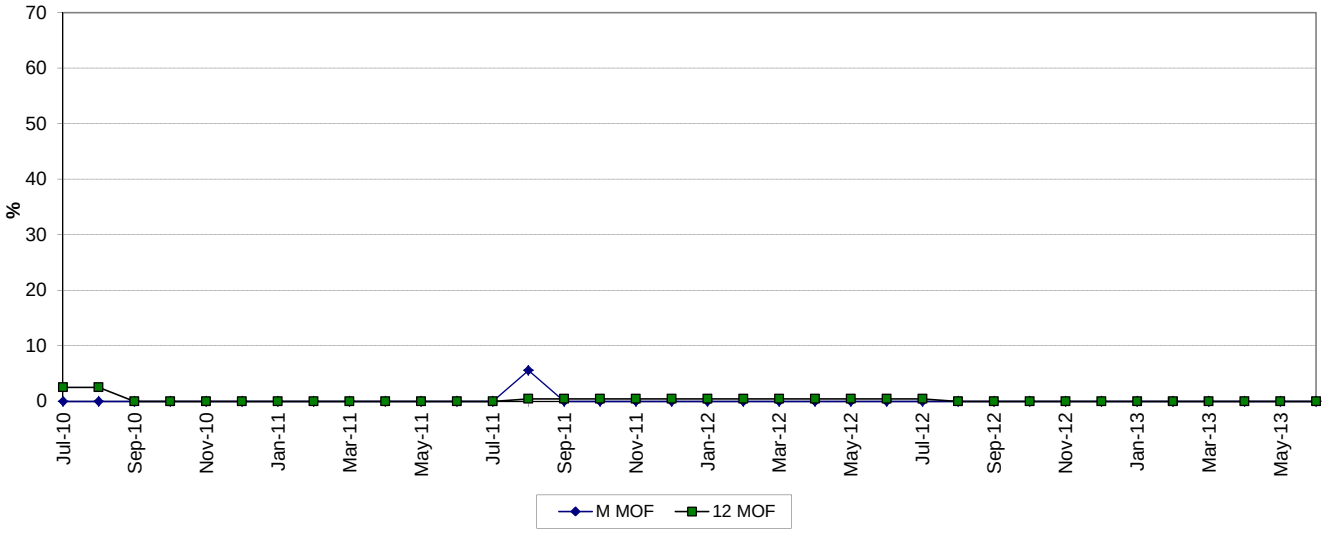
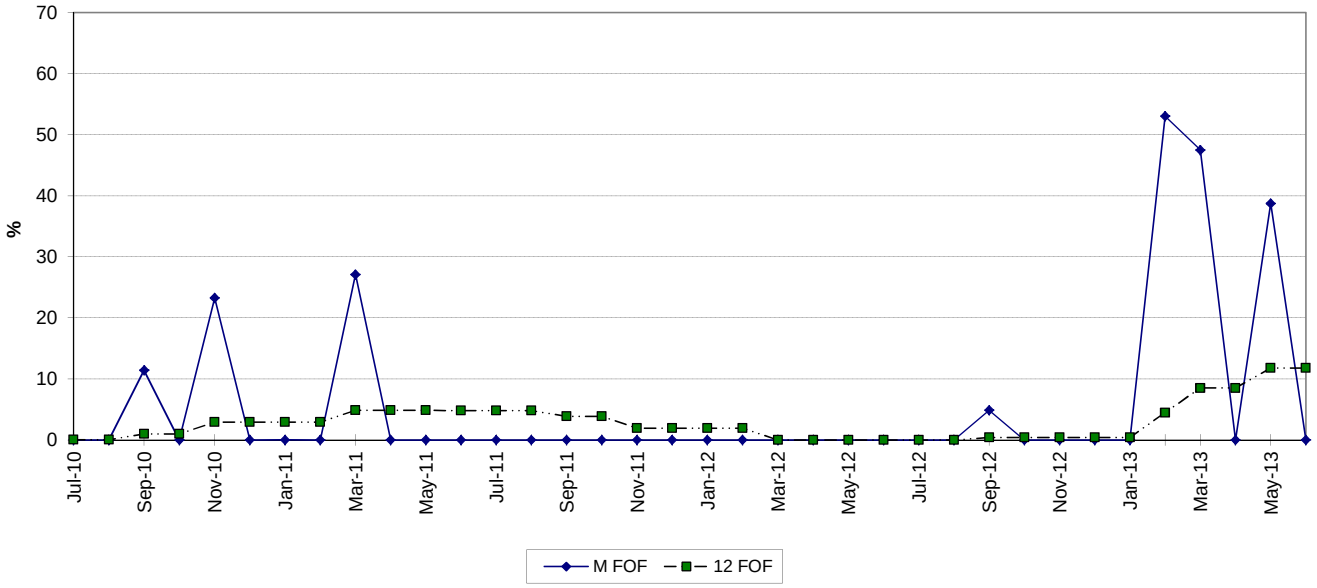


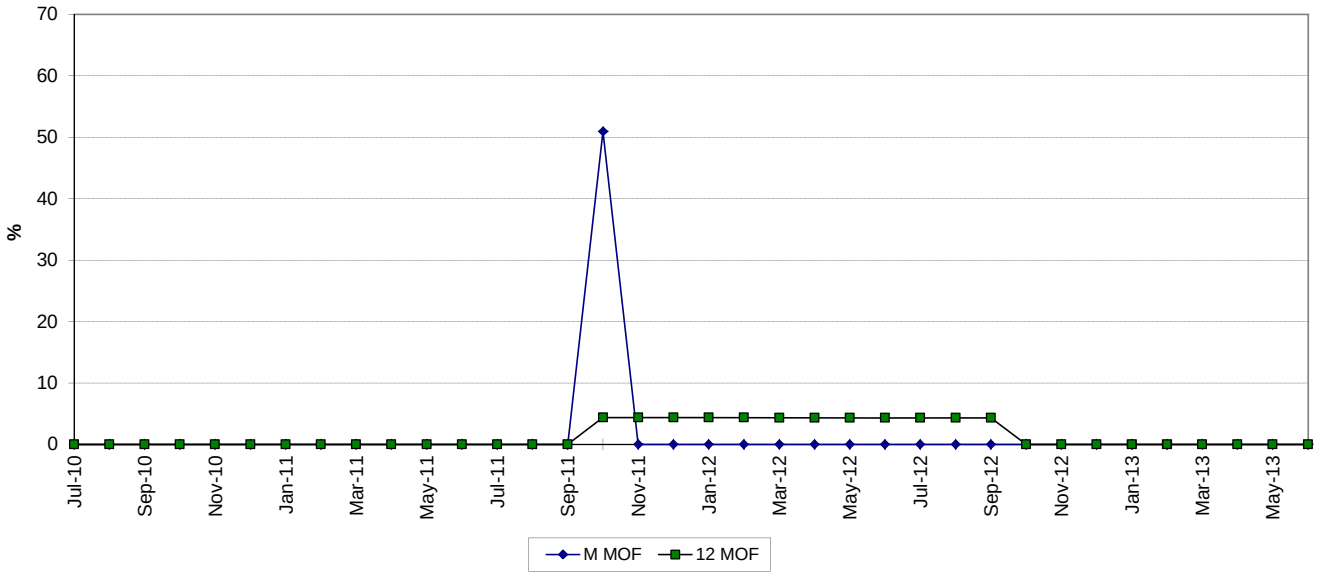
MAINTENANCE OUTAGE FACTOR



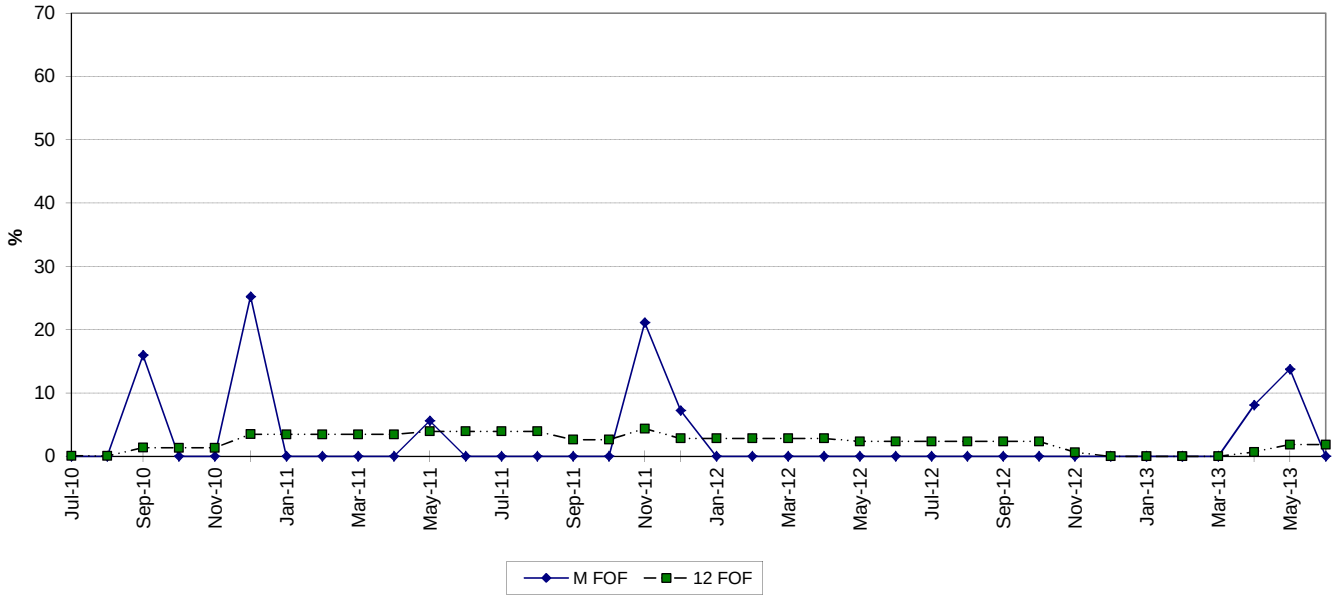
TURKEY POINT 3
FORCED OUTAGE FACTOR



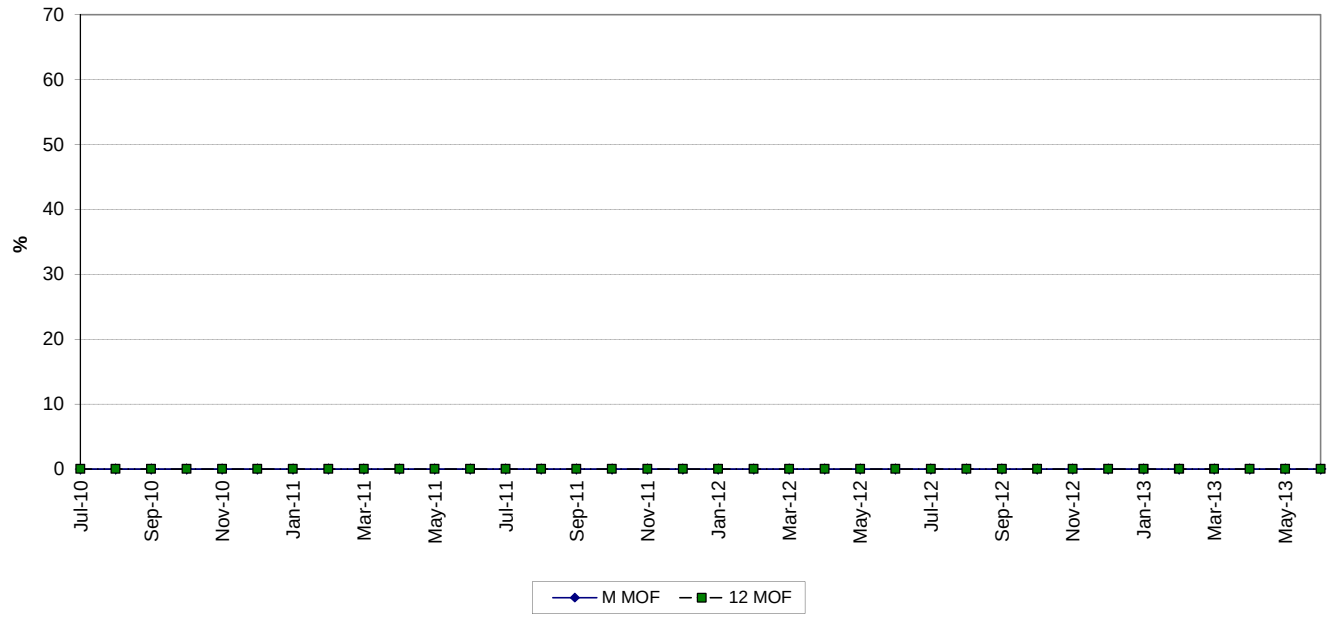
MAINTENANCE OUTAGE FACTOR



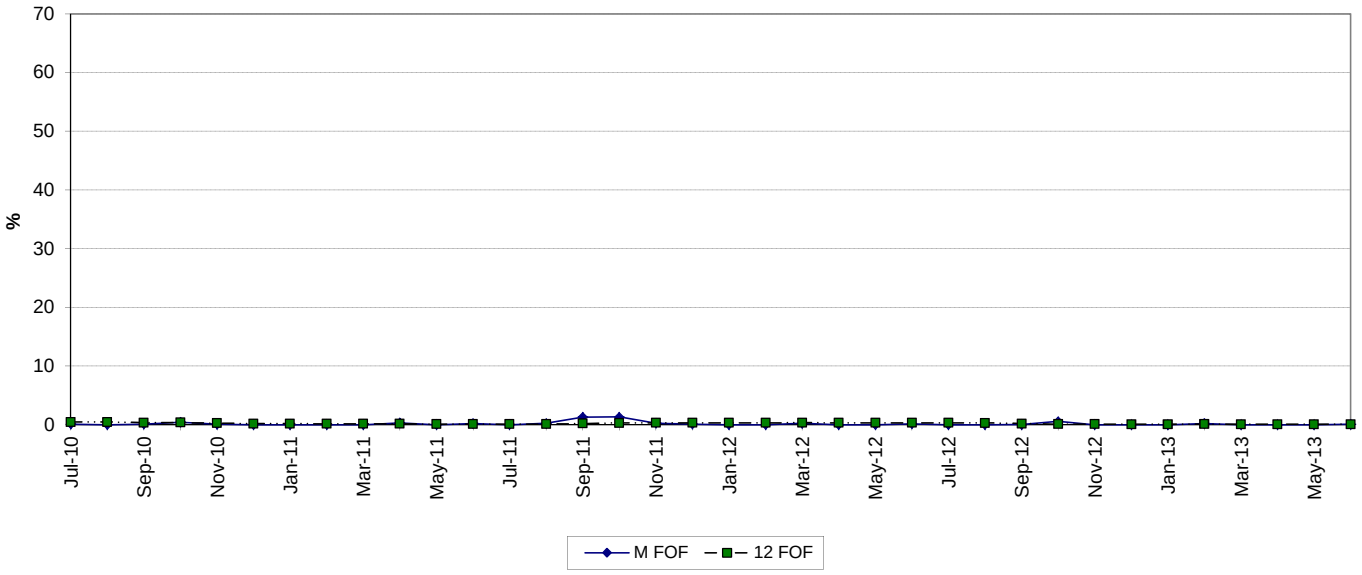
TURKEY POINT 4
FORCED OUTAGE FACTOR



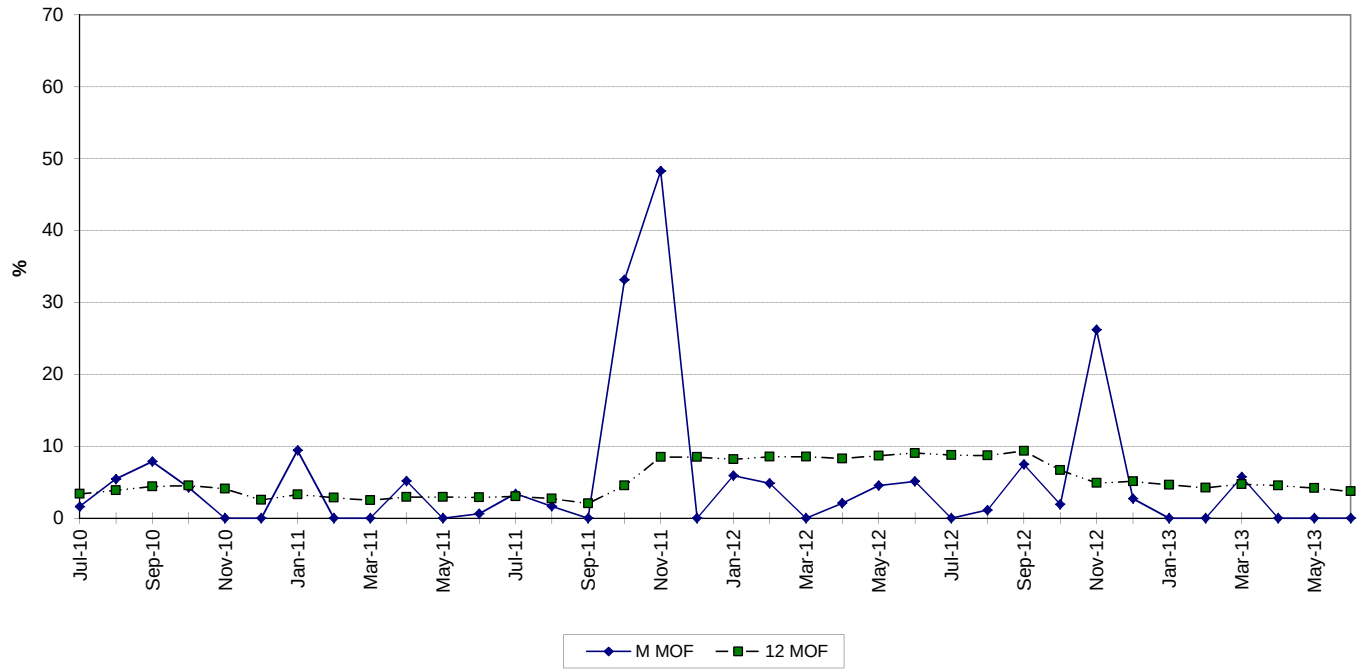
MAINTENANCE OUTAGE FACTOR



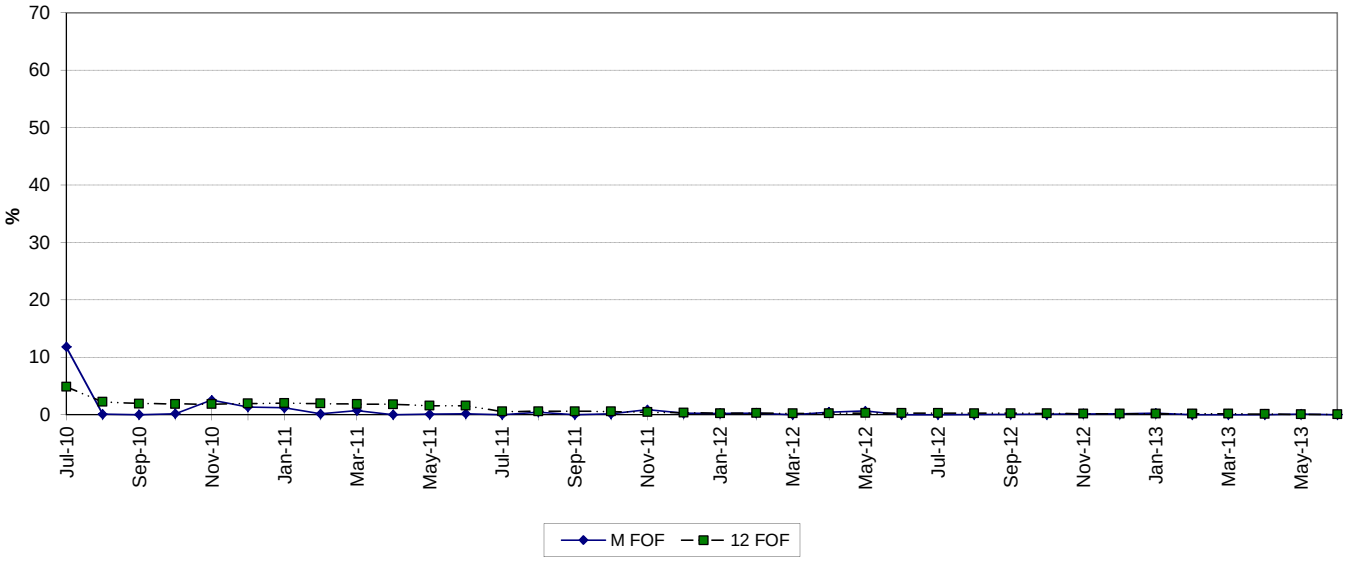
TURKEY POINT 5
FORCED OUTAGE FACTOR



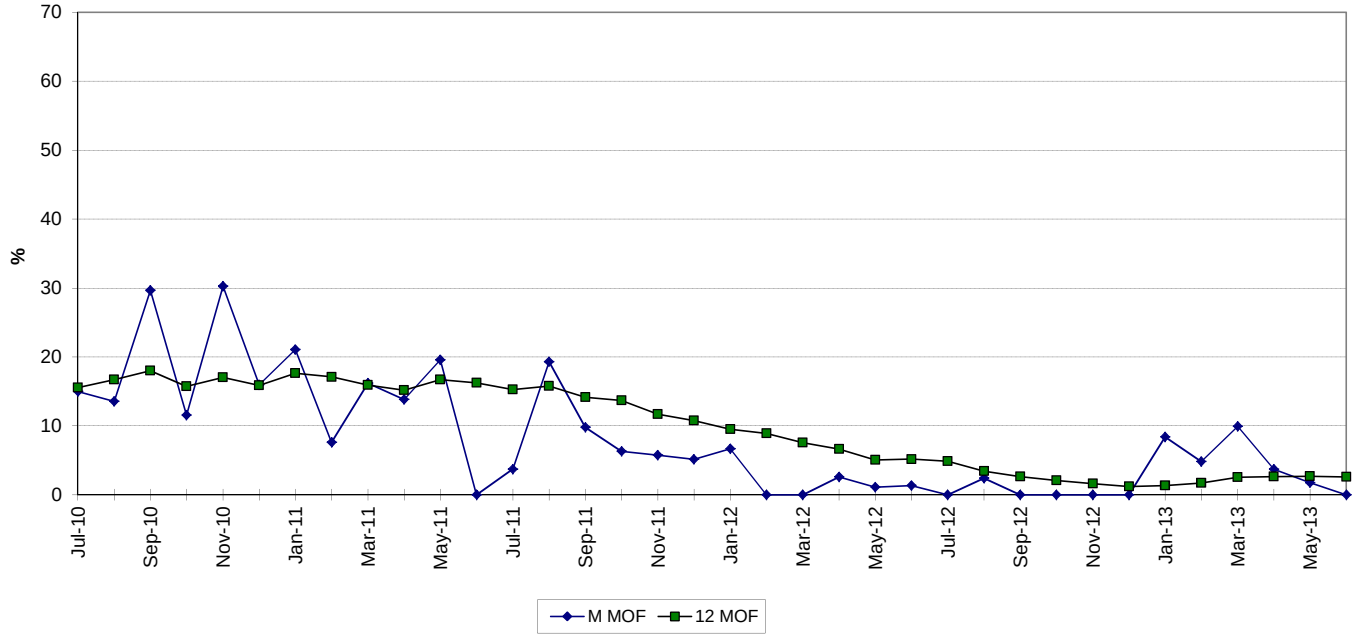
MAINTENANCE OUTAGE FACTOR



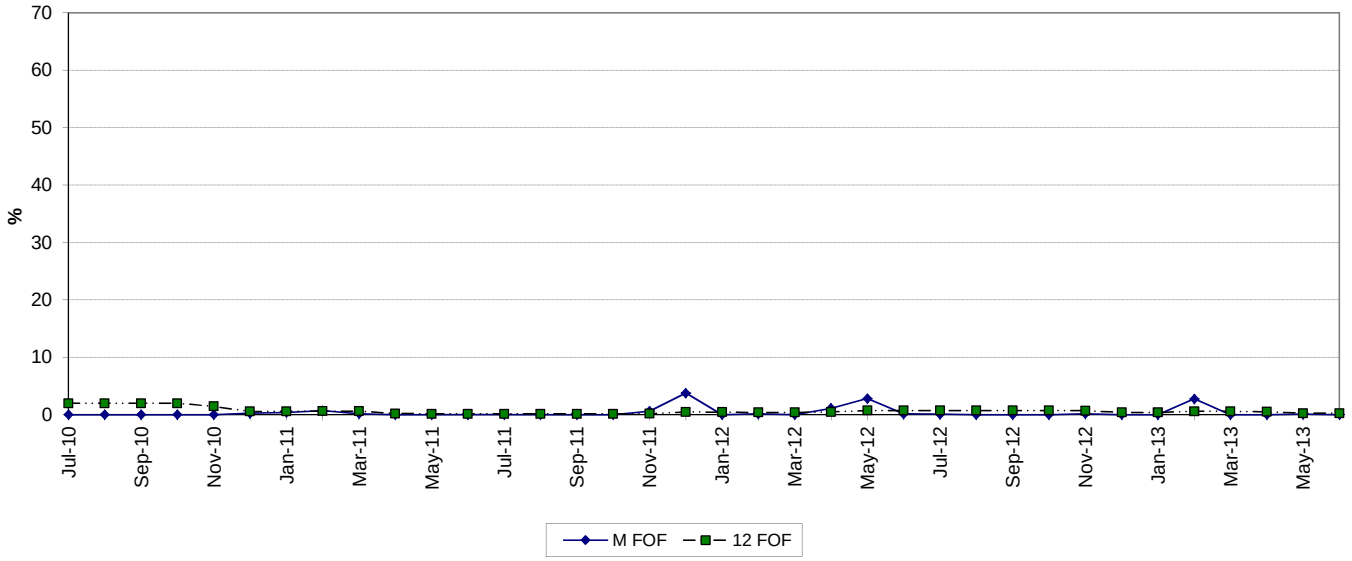
WEST COUNTY 1
FORCED OUTAGE FACTOR



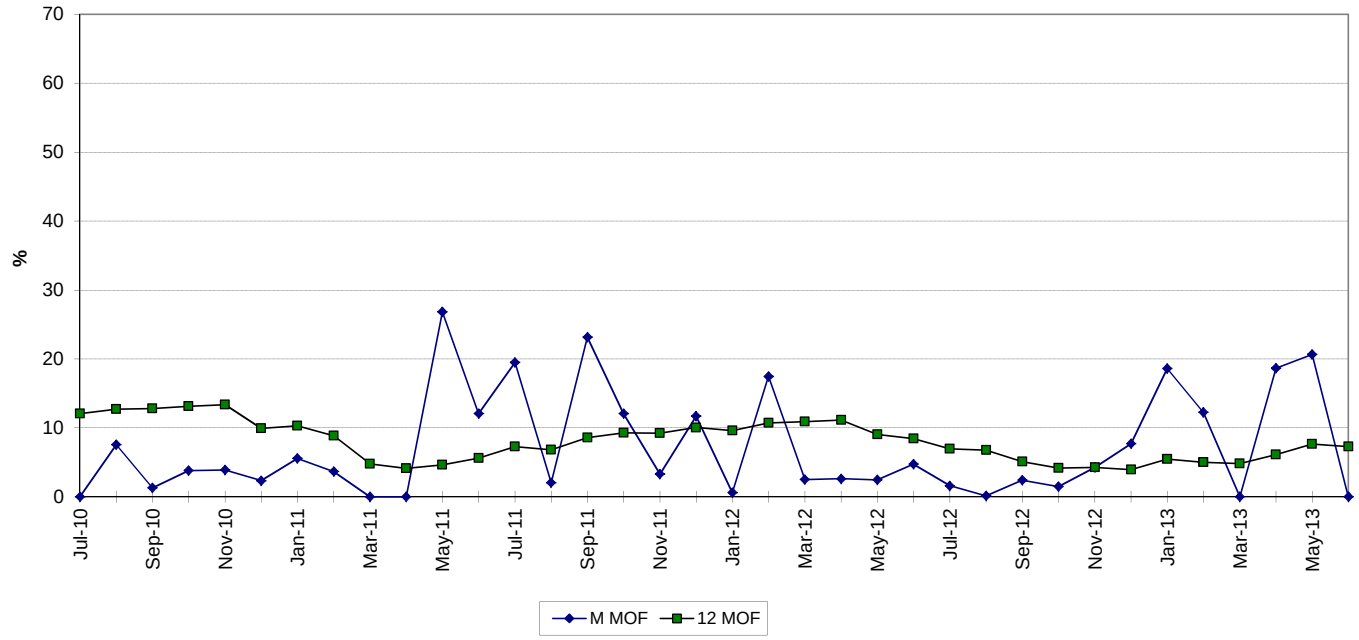
MAINTENANCE OUTAGE FACTOR



WEST COUNTY 2
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2014

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW*
Manatee 3	05/23/2014 - 06/14/2014	CT 3A 0.04 / CONTROLS / HOT GAS PATH/MINOR HRSG/GEN INSP - 25% CURT	263
Manatee 3	05/27/2014 - 06/18/2014	CT 3B 0.04 / CONTROLS / HOT GAS PATH/MINOR HRSG/GEN INSP - 25% CURT	263
Manatee 3	05/30/2014 - 06/17/2014	ST CONTROLS / P91 / ST GEN INSPECTION - 100% CURT	1052
Manatee 3	06/11/2014 - 07/03/2014	CT 3C 0.04 / CONTROLS / HOT GAS PATH/MINOR HRSG/GEN INSP - 25% CURT	263
Manatee 3	07/07/2014 - 08/05/2014	CT 3D 0.04 / CONTROLS / HOT GAS PATH/MINOR HRSG/GEN INSP - 25% CURT	270
Martin 8	02/15/2014 - 02/21/2014	CT 8C BOP/HRSG INSP - 25% CURT	282
Martin 8	03/08/2014 - 03/21/2014	CT 8A MAIN STM BYPASS VLV REPL/ HRSG INSP - 25% CURT	282
Martin 8	03/22/2014 - 03/28/2014	CT 8D BOP/HRSG INSP - 25% CURT	282
St. Lucie 1	NONE		0
St. Lucie 2	03/03/2014 - 04/06/2014	REFUELING	987
Turkey Point 3	03/17/2014 - 04/19/2014	REFUELING	808
Turkey Point 4	09/24/2014 10/30/2014	REFUELING	819
Turkey Point 5	02/01/2014 - 03/02/2014	CT 5A .04/MAJOR/PKG 4/RAINBOW- 25% CURT	278
Turkey Point 5	02/15/2014 - 02/26/2014	ST TURB VLV / AVR UPGRADE / GEN INSP - 100% CURT	1113
Turkey Point 5	02/15/2014 - 03/16/2014	CT 5B .04/MAJOR/PKG 4 - 25% CURT	278
Turkey Point 5	04/25/2014 - 06/29/2014	CT 5C & 5D .04/MAJORS/PKG 4 25% CURT EACH	267
Turkey Point 5	11/17/2014 - 12/07/2014	FGT GAS LINE OUTAGE - SITE	1146
West County 1	09/27/2014 - 11/05/2014	CT 1A MAJOR + 24K PARTS - 33% CURT	402
West County 1	10/01/2014 - 11/09/2014	CT 1C MAJOR + 24K PARTS - 33% CURT	402
West County 1	10/15/2014 - 11/09/2014	ST VALVES - 100% CURT	1219
West County 1	10/15/2014 - 11/24/2014	CT 1B MAJOR + 24K PARTS - 33% CURT	402
West County 2	06/14/2014 - 06/29/2014	CT 2A COMB INSP - 33% CURT	402
West County 2	06/18/2014 - 07/03/2014	CT 2C COMB INSP - 33% CURT	402
West County 2	06/23/2014 - 06/29/2014	BOP - 100% CURT	1219
West County 2	06/23/2014 - 07/12/2014	CT 2B COMB INSP - 33% CURT	402

*Load Reduction MW are based on the unit's estimated MW rating during the outage period

Progress Energy Florida
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January through December 2012

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional Kwh sales - difference	(531,793,886)
2	Non-Jurisdictional Kwh sales - difference	(601,156,235)
3	Total System Kwh sales - difference Schedule A2, pg 1 of 2, line B3	(1,132,950,121)
	System:	
4	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C4	$ (71,228,956)
	Jurisdictional:	
5	Fuel Revenues - difference Schedule A2, page 2 of 2, line C3	$ (58,236,231)
6	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C6 - C12 - C7	(42,359,344)
7	True Up amount for the period	(15,876,888)
8	True Up for the prior period Schedule A2, page 2 of 2, lines C9 + C10	(201,362,994)
9	Interest Provision Schedule A2, page 2 of 2, line C8	(337,717)
10	Actual True Up ending balance for the period January 2012 through December 2012 Schedule A2, page 2 of 2, line C13	(217,577,600)
11	Estimated True Up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2012, Docket No. 120001-EI.	(145,366,912)
12	Total True Up for the period January 2012 through December 2012	$ (72,210,688)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 21
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Thomas G. Foster - TGF-1T

Progress Energy Florida
Calculation of Actual True-up
For the Period of January through December 2012

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 113,629,995	$ 104,776,815	$ 112,516,110	$ 120,647,828	$ 132,375,786	$ 135,652,337	$ 719,598,872
	2	Fuel Cost of Power Sold	(2,275,653)	(3,535,730)	(3,055,736)	(3,550,599)	(3,411,215)	(4,230,684)	(20,059,618)
	3	Fuel Cost of Purchased Power	6,347,196	4,383,223	14,816,554	12,467,362	14,867,278	10,383,076	63,264,688
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	15,476,728	12,589,025	13,377,966	14,013,369	16,763,902	16,429,228	88,650,219
	4	Energy Cost of Economy Purchases	717,993	245,257	383,160	504,791	2,619,526	2,076,208	6,546,935
	5	Adjustments to Fuel Cost	(873,300)	(1,651,656)	(945,422)	(1,001,760)	(828,442)	(903,010)	(6,203,590)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	133,022,960	116,806,934	137,092,631	143,080,991	162,386,835	159,407,155	851,797,507
B	1	Jurisdictional KWH Sales	2,673,803	2,498,543	2,606,591	2,796,554	2,936,035	3,374,793	16,886,318
	2	Non-Jurisdictional KWH Sales	23,750	19,139	11,587	12,519	14,067	24,353	105,414
	3	TOTAL SALES (Lines B1 + B2)	2,697,553	2,517,682	2,618,178	2,809,072	2,950,102	3,399,146	16,991,733
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.12%	99.24%	99.56%	99.55%	99.52%	99.28%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	134,033,596	124,924,977	130,556,678	141,076,732	149,685,445	173,220,800	853,498,227
	1a	Adjustments to Fuel Revenue	0	0	0	0	0	0	-
	2	True-Up Provision	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(61,579,602)
	2a	Incentive Provision	248,341	248,341	248,341	248,341	248,341	248,341	1,490,046
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	124,018,670	114,910,051	120,541,752	131,061,806	139,670,519	163,205,874	793,408,671
	4	Fuel & Net Power Transactions (Line A6)	133,022,960	116,806,934	137,092,631	143,080,991	162,386,835	159,407,155	851,797,507
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	132,163,530	116,060,623	136,655,941	142,610,900	161,804,539	158,452,500	847,748,032
	6	Over/(Under) Recovery (Line 3 - Line 5)	(8,144,860)	(1,150,571)	(16,114,189)	(11,549,095)	(22,134,020)	4,753,374	(54,339,361)
	7	Interest Provision	(19,408)	(31,787)	(25,296)	(28,776)	(32,634)	(32,480)	(170,381)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(8,164,268)	(1,182,358)	(16,139,485)	(11,577,871)	(22,166,655)	4,720,894	(54,509,742)
	9	Plus: Prior Period Balance	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)
	10	Plus: Cumulative True-Up Provision	10,263,267	20,526,534	30,789,801	41,053,068	51,316,335	61,579,602	61,579,602
	11	Subtotal Prior Period True-up	(314,258,929)	(303,995,662)	(293,732,395)	(283,469,128)	(273,205,861)	(262,942,594)	(262,942,594)
	12	Regulatory Accounting Adjustment	0	0	127,186	0	0	0	127,186
	13	TOTAL TRUE-UP BALANCE	($322,423,196)	(313,342,287)	($319,091,320)	($320,405,924)	($332,309,311)	($317,325,151)	($317,325,151)

Progress Energy Florida
Calculation of Actual True-up
For the Period of January through December 2012

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 151,907,722	$ 152,312,145	$ 138,349,963	$ 128,706,089	$ 99,238,000	$ 98,398,929	$ 1,488,511,720
	2	Fuel Cost of Power Sold	(4,239,027)	(8,677,094)	(6,181,522)	(5,233,290)	(5,352,100)	(2,694,342)	(52,436,993)
	3	Fuel Cost of Purchased Power	19,372,300	16,163,299	12,465,549	12,172,323	5,052,601	8,622,088	137,112,849
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	16,634,973	17,187,160	16,288,106	11,123,057	14,007,133	24,687,666	188,578,313
	4	Energy Cost of Economy Purchases	2,770,326	3,055,032	425,457	1,044,701	165,548	166,973	14,174,973
	5	Adjustments to Fuel Cost	(1,704,299)	(12,119,811)	(1,101,725)	(797,448)	(1,079,752)	(274,818)	(23,281,444)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	184,741,995	167,920,732	160,245,828	147,015,431	112,031,430	128,906,495	1,752,659,418
B	1	Jurisdictional KWH Sales	3,354,924	3,875,021	3,512,414	3,318,345	2,920,347	2,514,087	36,381,457
	2	Non-Jurisdictional KWH Sales	25,111	31,251	31,754	31,552	25,861	20,935	271,877
	3	TOTAL SALES (Lines B1 + B2)	3,380,036	3,906,272	3,544,168	3,349,897	2,946,208	2,535,022	36,653,334
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.26%	99.20%	99.10%	99.06%	99.12%	99.17%	99.26%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	172,588,700	200,678,406	180,944,252	170,491,764	147,889,335	121,933,264	1,848,023,948
	1a	Adjustments to Fuel Revenue	0	0	0	0	0	0	-
	2	True-Up Provision	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,265)	(123,159,202)
	2a	Incentive Provision	248,341	248,341	248,341	248,341	248,341	248,339	2,980,090
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	162,573,774	190,663,480	170,929,326	160,476,838	137,874,409	111,918,339	1,727,844,836
	4	Fuel & Net Power Transactions (Line A6)	184,741,995	167,920,732	160,245,828	147,015,431	112,031,430	128,906,495	1,752,659,418
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	183,598,622	166,780,591	158,997,356	145,811,159	111,181,029	127,992,532	1,742,109,321
	6	Over/(Under) Recovery (Line 3 - Line 5)	(21,024,848)	23,882,889	11,931,969	14,665,679	26,693,380	(16,074,193)	(14,264,485)
	7	Interest Provision	(32,271)	(37,326)	(25,461)	(23,343)	(29,698)	(19,240)	(337,717)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(21,057,118)	23,845,564	11,906,508	14,642,336	26,663,683	(16,093,433)	(14,602,203)
	9	Plus: Prior Period Balance	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)
	10	Plus: Cumulative True-Up Provision	71,842,869	82,106,136	92,369,403	102,632,670	112,895,937	123,159,202	123,159,202
	11	Subtotal Prior Period True-up	(252,679,327)	(242,416,060)	(232,152,793)	(221,889,526)	(211,626,259)	(201,362,994)	(201,362,994)
	12	Regulatory Accounting Adjustment	0	13,429	0	0	0	(1,753,018)	(1,612,403)
	13	TOTAL TRUE-UP BALANCE	($328,119,002)	($293,996,742)	($271,826,967)	($246,921,364)	($209,994,414)	($217,577,600)	(217,577,600)

Progress Energy Florida
Calculation of 2012 Estimated/Actual True-up
For the Period of January through December 2012 (Filed August 1, 2012)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 113,629,995	$ 104,776,815	$ 112,516,110	$ 120,647,828	$ 132,375,786	$ 135,652,337	$ 719,598,872
	2	Fuel Cost of Power Sold	(2,275,653)	(3,535,730)	(3,055,736)	(3,550,599)	(3,411,215)	(4,230,684)	(20,059,618)
	3	Fuel Cost of Purchased Power	6,347,196	4,383,223	14,816,554	12,467,362	14,867,278	10,383,076	63,264,688
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	15,476,728	12,589,025	13,377,966	14,013,369	16,763,902	16,429,228	88,650,219
	4	Energy Cost of Economy Purchases	717,993	245,257	383,160	504,791	2,619,526	2,076,208	6,546,935
	5	Adjustments to Fuel Cost	(873,300)	(1,651,656)	(945,422)	(1,001,760)	(828,442)	(903,010)	(6,203,590)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	133,022,960	116,806,934	137,092,631	143,080,991	162,386,835	159,407,155	851,797,507
B	1	Jurisdictional KWH Sales	2,673,803	2,498,543	2,606,591	2,796,554	2,936,035	3,374,793	16,886,318
	2	Non-Jurisdictional KWH Sales	23,750	19,139	11,587	12,519	14,067	24,353	105,414
	3	TOTAL SALES (Lines B1 + B2)	2,697,553	2,517,682	2,618,178	2,809,072	2,950,102	3,399,146	16,991,733
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.12%	99.24%	99.56%	99.55%	99.52%	99.28%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	134,033,596	124,924,977	130,556,678	141,076,732	149,685,445	173,220,800	853,498,227
	1a	Adjustments to Fuel Revenue	0	0	0	0	0	0	-
	2	True-Up Provision	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(61,579,602)
	2a	Incentive Provision	248,341	248,341	248,341	248,341	248,341	248,341	1,490,046
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	124,018,670	114,910,051	120,541,752	131,061,806	139,670,519	163,205,874	793,408,671
	4	Fuel & Net Power Transactions (Line A6)	133,022,960	116,806,934	137,092,631	143,080,991	162,386,835	159,407,155	851,797,507
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	132,163,530	116,060,623	136,655,941	142,610,900	161,804,539	158,452,500	847,748,032
	6	Over/(Under) Recovery (Line 3 - Line 5)	(8,144,860)	(1,150,571)	(16,114,189)	(11,549,095)	(22,134,020)	4,753,374	(54,339,361)
	7	Interest Provision	(19,408)	(31,787)	(25,296)	(28,776)	(32,634)	(32,480)	(170,381)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(8,164,268)	(1,182,358)	(16,139,485)	(11,577,871)	(22,166,655)	4,720,894	(54,509,742)
	9	Plus: Prior Period Balance	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)
	10	Plus: Cumulative True-Up Provision	10,263,267	20,526,534	30,789,801	41,053,068	51,316,335	61,579,602	61,579,602
	11	Subtotal Prior Period True-up	(314,258,929)	(303,995,662)	(293,732,395)	(283,469,128)	(273,205,861)	(262,942,594)	(262,942,594)
	12	Regulatory Accounting Adjustment	0	0	127,186	0	0	0	127,186
	13	TOTAL TRUE-UP BALANCE	($322,423,196)	($313,342,287)	($319,091,320)	($320,405,924)	($332,309,311)	($317,325,151)	(317,325,151)

Progress Energy Florida
Calculation of 2012 Estimated/Actual True-up
For the Period of January through December 2012 (Filed August 1, 2012)

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 131,700,599	$ 132,257,655	$ 121,489,696	$ 111,141,122	$ 87,515,137	$ 98,256,685	$ 1,401,959,766
	2	Fuel Cost of Power Sold	(3,476,650)	(4,050,407)	(3,677,551)	(4,360,256)	(2,388,067)	(2,088,516)	(40,101,064)
	3	Fuel Cost of Purchased Power	28,808,464	30,127,624	24,545,617	21,267,512	13,708,416	8,723,986	190,446,307
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	14,184,021	14,185,046	13,572,173	11,732,938	13,364,810	15,284,982	170,974,188
	4	Energy Cost of Economy Purchases	891,055	968,670	787,965	704,151	642,551	543,939	11,085,266
	5	Adjustments to Fuel Cost	0	0	0	0	0	(10,928,571)	(17,132,161)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	172,107,488	173,488,588	156,717,901	140,485,467	112,842,847	109,792,504	1,717,232,302
B	1	Jurisdictional KWH Sales	3,601,965	3,778,360	3,717,309	3,228,460	2,911,308	2,749,668	36,873,388
	2	Non-Jurisdictional KWH Sales	18,844	21,217	22,671	20,565	17,272	13,975	219,958
	3	TOTAL SALES (Lines B1 + B2)	3,620,809	3,799,577	3,739,980	3,249,025	2,928,580	2,763,643	37,093,347
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.48%	99.44%	99.39%	99.37%	99.41%	99.49%	99.41%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	186,011,317	195,120,641	191,967,869	166,722,913	150,344,669	141,997,317	1,885,662,954
	1a	Adjustments to Fuel Revenue	0	0	0	0	0	0	-
	2	True-Up Provision	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,267)	(10,263,265)	(123,159,202)
	2a	Incentive Provision	248,341	248,341	248,341	248,341	248,341	248,339	2,980,090
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	175,996,391	185,105,715	181,952,943	156,707,987	140,329,743	131,982,392	1,765,483,842
	4	Fuel & Net Power Transactions (Line A6)	172,107,488	173,488,588	156,717,901	140,485,467	112,842,847	109,792,504	1,717,232,302
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	171,421,408	172,727,522	155,951,951	139,770,721	112,313,931	109,365,826	1,709,299,392
	6	Over/(Under) Recovery (Line 3 - Line 5)	4,574,983	12,378,193	26,000,992	16,937,266	28,015,813	22,616,565	56,184,450
	7	Interest Provision	(30,984)	(29,113)	(26,170)	(23,001)	(19,730)	(16,174)	(315,552)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	4,543,999	12,349,080	25,974,821	16,914,265	27,996,083	22,600,391	55,868,896
	9	Plus: Prior Period Balance	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)	(324,522,196)
	10	Plus: Cumulative True-Up Provision	71,842,869	82,106,136	92,369,403	102,632,670	112,895,937	123,159,202	123,159,202
	11	Subtotal Prior Period True-up	(252,679,327)	(242,416,060)	(232,152,793)	(221,889,526)	(211,626,259)	(201,362,994)	(201,362,994)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	127,186
	13	TOTAL TRUE-UP BALANCE	($302,517,885)	($279,905,538)	($243,667,450)	($216,489,917)	($178,230,567)	($145,366,912)	(145,366,912)

Progress Energy Florida
Fuel and Net Power Cost Variance Analysis
January through December 2012

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	(2,700,343)	(76,511)	(276,070)	(3,052,924)
2	Light Oil	(4,854,612)	(11,705,856)	(2,658,967)	(19,219,435)
3	Coal	(92,088,783)	16,402,815	22,430,929	(53,255,039)
4	Gas	108,092,809	30,564,625	(179,715,728)	(41,058,294)
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	39,840	39,840
7	Total Generation	8,449,071	35,185,073	(160,179,996)	(116,545,852)
8	Firm Purchases	(72,708,571)	0	(32,503,379)	(105,211,950)
9	Economy Purchases	1,171,304	0	(1,544,160)	(372,856)
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	6,460,646	0	(2,469,875)	3,990,771
12	Total Purchases	(65,076,621)	0	(36,517,414)	(101,594,035)
13	Economy Sales	0	0	0	0
14	Other Power Sales	363,545	0	480,206	843,751
15	Supplemental Sales	31,745,777	0	19,369,080	51,114,857
16	Total Sales	32,109,322	0	19,849,286	51,958,608
17	Nuclear Fuel Disposal Cost	0	0	0	0
18	Nuclear Decom & Decon	0	0	0	0
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 2 Line 6b	0	0	94,952,323	94,952,323
20	Total Fuel and Net Power Cost Variance	(24,518,228)	35,185,073	(81,895,801)	(71,228,956)

Progress Energy Florida
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2012

Line No.	Description	Actual	Original Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 48	$ 453,875,100	$ 459,796,135	$ (5,921,035)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 44	469,731,498	$ 459,796,135	9,935,363
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 51	(7,924)	0	(7,924)
4	Sub Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 52	$ (15,864,322)	$ -	$ (15,864,322)
5	Prior Period True-up - January through December 2012- Over/(Under) Recovery Sheet 2 of 3, Line 53	16,277,953	20,667,503	(4,389,550)
6	Prior Period True-up - January through December 2012 - (Refunded)/Collected Sheet 2 of 3, Line 54	(20,667,503)	(20,667,503)	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2012 Sheet 2 of 3, Line 57	$ (20,253,872)	$ -	$ (20,253,872)
8	Estimated True-up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2012 Docket No. 120001-EI. (Sheet 3 of 3, Line 56)	(10,485,622)		
9	Total Over/(Under) Recovery for the period January through December 2012 (Line 7 - Line 8)	$ (9,768,250)		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 22
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Thomas G. Foster - TGF-2T

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January Through December 2012

		ACTUAL JAN	ACTUAL FEB	ACTUAL MAR	ACTUAL APR	ACTUAL MAY	ACTUAL JUN	ACTUAL JUL	ACTUAL AUG	ACTUAL SEP	ACTUAL OCT	ACTUAL NOV	ACTUAL DEC	YTD
1	**Base Production Level Capacity Charges:**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	9,304,440
3	Auburndale Power Partners, L.P. (AUBSET)	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,395	3,437,396	3,437,396	3,437,396	3,437,395	3,437,396	41,248,750
4	Lake County (LAKCOUNT)	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	8,722,536
5	Lake Cogen Limited (LAKORDER)	3,553,265	3,553,265	3,553,265	3,553,264	3,553,265	3,553,265	3,553,264	3,553,265	3,553,265	3,553,265	3,553,264	3,553,265	42,639,177
6	Metro-Dade County (METRDADE)	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	16,016,640
7	Orange Cogen (ORANGECO)	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,600	2,813,601	2,813,601	2,813,601	33,763,211
8	Orlando Cogen Limited (ORLACOGL)	2,682,225	2,675,845	2,676,294	2,740,784	2,740,783	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,783	2,740,784	32,701,418
9	Pasco County Resource Recovery (PASCOUNT)	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	15,734,760
10	Pinellas County Resource Recovery (PINCOUNT)	3,121,298	3,121,298	3,121,298	3,121,298	3,121,297	3,121,298	3,121,297	3,121,297	3,121,298	3,121,297	3,121,298	3,121,297	37,455,571
11	Polk Power Partners, L.P. (MULBERRY)	5,431,879	5,431,880	5,431,880	5,431,880	5,431,879	5,431,878	5,431,880	5,431,880	5,431,879	5,431,880	5,431,880	5,431,880	65,182,555
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,947	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,353
13	UPS Purchase (414 total mw) - Southern	0	0	(230,855)	0	0	0	0	0	(16,836)	0	0	0	(247,691)
14	Southern - Scherer	1,666,586	1,661,304	1,663,945	1,663,945	2,237,943	1,558,717	1,718,299	1,705,138	1,710,820	1,711,718	1,709,996	1,711,113	20,719,524
15	Subtotal - Base Level Capacity Charges	27,655,395	27,643,733	27,415,968	27,711,312	28,285,308	27,606,083	27,765,664	27,752,505	27,741,350	27,759,085	27,757,361	27,758,480	332,852,244
16	Base Production Jurisdictional Responsibility	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	
17	Base Level Jurisdictional Capacity Charges	25,355,295	25,344,604	25,135,782	25,406,562	25,932,819	25,310,085	25,456,394	25,444,329	25,434,102	25,450,362	25,448,781	25,449,807	305,168,923
18	**Intermediate Production Level Capacity Charges:**													
19	Southern - Franklin	2,163,000	2,163,000	2,163,000	2,768,640	3,289,165	2,291,019	3,063,230	3,006,201	3,361,856	2,999,467	3,027,032	3,030,258	33,325,868
20	Schedule H Capacity Sales-NSB	(11,552)	(10,807)	(11,552)	(11,179)	(11,307)	(10,942)	(11,307)	(11,307)	(10,942)	(11,307)	(14,468)	(14,792)	(141,462)
21	Subtotal - Intermediate Level Capacity Charges	2,151,448	2,152,193	2,151,448	2,757,461	3,277,858	2,280,077	3,051,923	2,994,894	3,350,914	2,988,160	3,012,564	3,015,466	33,184,406
22	Intermediate Production Jurisdict. Responsibility	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	
23	Intermediate Level Jurisdict. Capacity Charges	1,388,093	1,388,573	1,388,093	1,779,086	2,114,841	1,471,083	1,969,070	1,932,276	2,161,976	1,927,931	1,943,676	1,945,549	21,410,247
24	**Peaking Production Level Capacity Charges:**													
25	Chattahoochee Capacity Purchase	12,500	11,513	13,084	12,634	12,366	12,634	12,769	12,500	12,231	12,769	12,231	12,769	150,000
26	Vandolah Capacity - Northern Star	0	0	0	0	0	(1,734)	1,734	0	0	0	0	0	-
27	Seminole Electric Cooperative, Inc	0	0	0	0	0	(47,292)	47,292	0	0	0	0	0	-
28	Reliant - Vandolah Capacity Purchase	1,418,840	1,418,840	1,014,360	1,014,360	1,418,840	5,599,810	5,818,316	5,840,887	2,711,658	1,916,830	2,014,083	2,942,812	33,129,636
29	Shady Hills Power Company LLC	1,965,615	1,965,615	1,404,011	1,362,100	1,908,900	3,879,900	3,879,900	3,879,900	1,810,620	1,363,500	1,363,500	1,969,380	26,752,941
30	Subtotal -Peaking Level Capacity Charges	3,396,955	3,395,968	2,431,455	2,389,094	3,340,106	9,443,318.00	9,760,011	9,733,287	4,534,509	3,293,099	3,389,814	4,924,961	60,032,577
31	Peaking Production Jurisdictional Responsibility	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	
32	Peaking Level Jurisdictional Capacity Charges	3,238,623	3,237,882	2,318,125	2,277,738	3,184,424	9,003,165	9,305,097	9,279,618	4,323,156	3,139,608	3,231,815	4,695,409	57,234,459
33	**Other Capacity Charges:**													
34	Retail Wheeling	(2,932)	(1,199)	(455)	(3,033)	(1,120)	(2,803)	(12,128)	(2,527)	(1,328)	(2,613)	(2,034)	(995)	(33,167)
35	Total Other Capacity Charges	(2,932)	(1,199)	(455)	(3,033)	(1,120)	(2,803)	(12,128)	(2,527)	(1,328)	(2,613)	(2,034)	(995)	(33,167)
36														
37	**Subtotal Jurisdictional Capacity Charges (lines 17+23+32+35)**	29,979,079	29,969,660	28,841,545	29,460,354	31,230,964	35,781,530	36,718,433	36,653,696	31,917,906	30,515,288	30,622,238	32,089,769	383,780,461
38														
39	**Nuclear Cost Recovery Clause Charges:**													
40	Levy Costs	6,337,833	7,810,874	6,296,044	6,291,658	6,519,755	6,194,943	6,226,912	6,313,327	7,128,277	7,180,333	7,034,232	7,022,525	80,356,713
41	CR-3 Uprate Costs	465,111	465,187	465,298	465,445	465,628	465,848	466,105	466,399	466,731	467,101	467,510	467,958	5,594,321
42	**Total NCRC Costs - Order No. PSC-11-0095-FOF-EI**	6,802,944	8,276,061	6,761,342	6,757,103	6,985,383	6,660,791	6,693,017	6,779,726	7,595,008	7,647,434	7,501,742	7,490,483	85,951,034
43														
44	**Total Jurisdictional Capacity Charges (Lines 37 + 42)**	36,782,023	38,245,722	35,602,887	36,217,457	38,216,348	42,442,321	43,411,450	43,433,423	39,512,914	38,162,722	38,123,980	39,580,252	469,731,498
45	**Capacity Revenues:**													
46	Capacity Cost Recovery Revenues (net of tax)	31,537,270	29,146,074	30,584,102	32,837,024	34,730,095	40,480,643	40,243,819	47,278,095	42,140,150	39,838,766	34,515,623	29,875,935	433,207,597
47	Prior Period True-Up Provision	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	20,667,503
48	Current Period CCR Revenues (net of tax)	33,259,562	30,868,366	32,306,394	34,559,316	36,452,387	42,202,935	41,966,111	49,000,387	43,862,442	41,561,058	36,237,915	31,598,227	453,875,100
49	**True-Up Provision - Current Year (Acct 1823203/2543203)**													
50	True-Up Provision - Over/(Under) Recov (line 48-line 44)	(3,522,461)	(7,377,355)	(3,296,492)	(1,658,141)	(1,763,961)	(239,386)	(1,445,339)	5,566,965	4,349,528	3,398,336	(1,886,065)	(7,982,025)	(15,856,398)
51	Interest Provision for the Month	860	649	(45)	(430)	(821)	(1,093)	(1,350)	(1,579)	(893)	(700)	(1,137)	(1,386)	(7,924)
52	Total current month over/(under) recovery (Acct 4560097,5572001)	(3,521,601)	(10,898,307)	(14,194,844)	(15,853,415)	(17,618,197)	(17,858,676)	(19,305,365)	(13,739,979)	(9,391,344)	(5,993,708)	(7,880,910)	(15,864,321)	(15,864,322)
53	Prior Year True-Up & Interest Prov. (Begin Bal)-Over/(Under)	16,277,953	14,555,661	12,833,369	11,111,077	9,388,785	7,666,493	5,944,201	4,221,909	2,499,617	777,325	(944,967)	(2,667,259)	16,277,953
54	Prior YearTrue-Up Collected/(Refunded)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(1,722,292)	(20,667,503)
55	Prior Year True-Up & Interest Provision End Bal - (DR)/CR	14,555,661	12,833,369	11,111,077	9,388,785	7,666,493	5,944,201	4,221,909	2,499,617	777,325	(944,967)	(2,667,259)	(4,389,551)	(4,389,550)
56														
57	**Net Capacity True-up Over/(Under) (lines 52+55)**	$11,034,060	$1,935,062	($3,083,767)	($6,464,630)	($9,951,704)	($11,914,475)	($15,083,456)	($11,240,362)	($8,614,019)	($6,938,675)	($10,548,169)	($20,253,872)	($20,253,872)

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Estimated/Actual True-Up
January- December 2012 (Filed 08/01/2012)

		ACT Jan-12	ACT Feb-12	ACT Mar-12	ACT Apr-12	ACT May-12	ACT Jun-12	EST Jul-12	EST Aug-12	EST Sep-12	EST Oct-12	EST Nov-12	EST Dec-12	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$775,370	$9,304,440
3	Auburndale Power Partners, L.P. (AUBSET)	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	41,248,751
4	Lake County (LAKCOUNT)	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	8,722,533
5	Lake Cogen Limited (LAKORDER)	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	42,639,180
6	Metro-Dade County (METRDADE)	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	16,016,640
7	Orange Cogen (ORANGECO)	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	33,763,214
8	Orlando Cogen Limited (ORLACOGL)	2,682,226	2,675,846	2,676,295	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	32,701,423
9	Pasco County Resource Recovery (PASCOUNT)	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	15,734,760
10	Pinellas County Resource Recovery (PINCOUNT)	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	37,455,573
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,879	5,431,879	5,431,879	5,431,879	5,431,879	5,431,879	65,182,551
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,351
13	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
14	UPS Purchase (414 total mw) - Southern	-	-	(230,855)	-	-	-	-	-	-	-	-	-	(230,855)
15	Southern - Scherer	1,666,586	1,661,304	1,663,945	1,663,945	2,237,943	1,558,717	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	19,624,160
16	Subtotal - Base Level Capacity Costs	27,655,394	27,643,732	27,415,967	27,711,312	28,285,309	27,606,083	27,575,987	27,575,987	27,575,987	27,575,987	27,575,987	27,575,987	331,773,720
17	Base Production Jurisdictional Responsibility	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	91.683%	0.000%
18	Base Level Jurisdictional Capacity Costs	25,355,295	25,344,603	25,135,781	25,406,562	25,932,820	25,310,086	25,282,492	25,282,492	25,282,492	25,282,492	25,282,492	25,282,492	304,180,099
19	**Intermediate Production Level Capacity Costs**													
20	TECO Power Purchase (70 mw)	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Southern - Franklin	2,163,000	2,163,000	2,163,000	2,768,640	3,289,165	2,291,019	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	27,815,823
22	Schedule H Capacity Sales - NSB & RCID	(11,552)	(10,807)	(11,552)	(11,179)	(11,307)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(132,992)
23	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Subtotal - Intermediate Level Capacity Costs	2,151,448	2,152,193	2,151,448	2,757,461	3,277,858	2,280,077	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	27,682,832
25	Intermediate Production Jurisdictional Responsibility	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	64.519%	0.000%
26	Intermediate Level Jurisdictional Capacity Costs	1,388,093	1,388,574	1,388,093	1,779,086	2,114,841	1,471,083	1,388,486	1,388,486	1,388,486	1,388,486	1,388,486	1,388,486	17,860,687
27	**Peaking Production Level Capacity Costs**	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Chattahoochee	12,500	11,513	13,084	12,634	12,366	12,634	12,634	12,634	12,634	12,634	12,634	12,634	150,537
29	Vandolah (RRI)	1,418,840	1,418,840	1,014,360	1,014,360	1,418,840	5,599,810	-	-	-	-	-	-	11,885,050
30	Shady Hills Power Company LLC	1,965,615	1,965,615	1,404,011	1,362,100	1,908,900	3,879,900	4,183,488	4,183,488	1,952,294	1,394,496	1,394,496	1,952,294	27,546,699
31	Vandolah (NSG)	-	-	-	-	-	(1,734)	5,384,448	5,340,672	2,520,403	1,838,592	1,882,368	2,676,173	19,640,922
32	Other	-	-	-	-	-	(47,292)	-	-	-	-	-	-	(47,292)
33	Subtotal - Peaking Level Capacity Costs	3,396,955	3,395,968	2,431,455	2,389,095	3,340,106	9,443,318	9,580,570	9,536,794	4,485,332	3,245,722	3,289,498	4,641,102	59,175,916
34	Peaking Production Jurisdictional Responsibility	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	95.339%	0.000%
35	Peaking Level Jurisdictional Capacity Costs	3,238,623	3,237,682	2,318,125	2,277,739	3,184,423	9,003,165	9,134,020	9,092,284	4,276,271	3,094,439	3,136,175	4,424,780	56,417,727
36	**Other Capacity Costs**													
37	Retail Wheeling	(2,932)	(1,199)	(455)	(3,033)	(1,120)	(2,803)	(6,413)	(20,895)	(2,233)	(50,935)	(6,787)	(4,111)	(102,915)
38	Other Jurisdictional Capacity Costs	(2,932)	(1,199)	(455)	(3,033)	(1,120)	(2,803)	(6,413)	(20,895)	(2,233)	(50,935)	(6,787)	(4,111)	(102,915)
39	**Subtotal Jurisd Capacity Costs (Line 18+26+35+38)**	29,979,079	29,969,660	28,841,544	29,460,354	31,230,965	35,781,531	35,798,585	35,742,367	30,945,017	29,714,482	29,800,367	31,091,647	378,355,598
40	**Nuclear Cost Recovery Clause Costs**	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Levy Costs	6,337,833	7,810,874	6,296,044	6,291,658	6,519,755	6,194,943	6,226,912	6,313,327	7,128,277	7,180,333	7,034,232	7,022,526	80,356,714
42	CR3 Uprate Costs	465,111	465,187	465,298	465,445	465,628	465,848	466,105	466,399	466,731	467,101	467,510	467,959	5,594,322
43	**Total NCRC Costs - Order No. PSC-11-0547-FOF-EI**	6,802,944	8,276,061	6,761,342	6,757,103	6,985,383	6,660,791	6,693,017	6,779,726	7,595,008	7,647,434	7,501,742	7,490,485	85,951,036
44	**Total Jurisdictional Capacity Costs (Line 39+43)**	36,782,023	38,245,721	35,602,886	36,217,457	38,216,348	42,442,322	42,491,602	42,522,093	38,540,025	37,361,916	37,302,109	38,582,132	464,306,634
45	**Capacity Revenues**													
46	Capacity Cost Recovery Revenues (net of tax)	31,537,269	29,146,074	30,584,102	32,837,024	34,730,095	40,480,643	42,935,423	45,038,051	44,310,323	38,483,243	34,702,791	32,776,043	437,561,083
47	Prior Period True-Up Provision Over/(Under) Recovery	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	1,722,292	20,667,503
48	**Current Period Revenues (net of tax)**	33,259,561	30,868,366	32,306,394	34,559,316	36,452,387	42,202,935	44,657,715	46,760,343	46,032,615	40,205,535	36,425,083	34,498,334	458,228,586
49	**True-Up Provision**													
50	True-Up Provision - Over/(Under) Recov (Line 48-44)	(3,522,462)	(7,377,356)	(3,296,492)	(1,658,140)	(1,763,960)	(239,387)	2,166,113	4,238,250	7,492,591	2,843,619	(877,025)	(4,083,797)	(6,078,046)
51	Interest Provision for the Month	860	648	(46)	(430)	(821)	(1,093)	(610)	(1,100)	(2,043)	(2,577)	(3,551)	(7,264)	(18,026)
52	Current Cycle Balance - Over/(Under)	(3,521,602)	(10,898,309)	(14,194,847)	(15,853,417)	(17,618,198)	(17,858,678)	(15,693,175)	(11,456,025)	(3,965,477)	(1,124,435)	(2,005,011)	(6,096,072)	(6,096,072)
53	Prior Period Balance - Over/(Under) Recovered	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953	16,277,953
54	Prior Period Cumulative True-Up Collected/(Refunded)	(1,722,292)	(3,444,584)	(5,166,876)	(6,889,168)	(8,611,460)	(10,333,752)	(12,056,043)	(13,778,335)	(15,500,627)	(17,222,919)	(18,945,211)	(20,667,503)	(20,667,503)
55	Prior Period True-up Balance - Over/(Under)	14,555,661	12,833,369	11,111,077	9,388,785	7,666,493	5,944,201	4,221,910	2,499,618	777,326	(944,966)	(2,667,258)	(4,389,550)	(4,389,550)
56	**Net Capacity True-up Over/(Under) (Line 52+55)**	$11,034,059	$1,935,060	($3,083,770)	($6,464,632)	($9,951,704)	($11,914,476)	($11,471,266)	($8,956,408)	($3,188,152)	($2,069,401)	($4,672,269)	($10,485,622)	($10,485,622)

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER

DECEMBER 2012

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	98,398,929	114,052,660	(15,653,731)	(13.7)	2,407,515	2,528,474	(120,959)	(4.8)	4.0872	4.5107	(0.4235)	(9.4)
2	SPENT NUCLEAR FUEL DISPOSAL COST	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3a	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(274,818)	0	(274,818)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4a	ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	98,124,111	114,052,660	(15,928,549)	(14.0)	2,407,515	2,528,474	(120,959)	(4.8)	4.0757	4.5107	(0.4350)	(9.6)
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	8,622,088	17,969,895	(9,347,807)	(52.0)	201,901	298,433	(96,532)	(32.4)	4.2705	6.0213	(1.7508)	(29.1)
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	1,409	0	1,409	0.0	50	0	50	0.0	2.8180	0.0000	2.8180	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	165,564	1,032,097	(866,533)	(84.0)	805	20,094	(19,289)	(96.0)	20.5670	5.1363	15.4307	300.4
9	ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	24,687,666	17,373,434	7,314,231	42.1	403,501	355,434	48,067	13.5	6.1184	4.8879	1.2305	25.2
12	TOTAL COST OF PURCHASED POWER	33,476,727	36,375,226	(2,898,500)	(8.0)	606,257	673,961	(67,704)	(10.1)	5.5219	5.3972	0.1247	2.3
13	TOTAL AVAILABLE MWH					3,013,772	3,202,435	(188,663)	(5.9)				
14	FUEL COST OF ECONOMY SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
14a	GAIN ON ECONOMY SALES - 100% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
15	FUEL COST OF OTHER POWER SALES (SCH A6)	(52,724)	(25,495)	(27,229)	106.8	(1,447)	(590)	(857)	145.3	3.6437	4.3212	(0.6775)	(15.7)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6) *	(8,766)	(2,804)	(5,962)	212.6	(1,447)	(590)	(857)	145.3	0.6058	0.4753	0.1305	27.5
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16	FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17	FUEL COST OF STRATIFIED SALES	(2,632,853)	(6,153,502)	3,520,649	(57.2)	(67,380)	(133,295)	65,915	(49.5)	3.9075	4.6165	(0.7090)	(15.4)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(2,694,342)	(6,181,801)	3,487,459	(56.4)	(68,827)	(133,885)	65,058	(48.6)	3.9147	4.6172	(0.7025)	(15.2)
19	NET INADVERTENT AND WHEELED INTERCHANGE					24,037	0	24,037					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	128,906,495	144,246,085	(15,339,590)	(10.6)	2,968,982	3,068,550	(99,568)	(3.2)	4.3418	4.7008	(0.3590)	(7.6)
21	NET UNBILLED	11,255,053	1,910,068	9,344,985	489.3	(259,227)	(40,633)	(218,594)	538.0	0.4440	0.0673	0.3767	559.7
22	COMPANY USE	635,293	564,095	71,198	12.6	(14,632)	(12,000)	(2,632)	21.9	0.0251	0.0199	0.0052	26.1
23	T & D LOSSES	6,951,225	8,423,537	(1,472,312)	(17.5)	(160,101)	(179,194)	19,093	(10.7)	0.2742	0.2969	(0.0227)	(7.7)
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	128,906,495	144,246,085	(15,339,590)	(10.6)	2,535,022	2,836,723	(301,701)	(10.6)	5.0850	5.0850	0.0000	0.0
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(1,069,924)	(3,274,386)	2,204,462	(67.3)	(20,935)	(64,431)	43,496	(67.5)	5.1106	5.0820	0.0288	0.6
26	JURISDICTIONAL KWH SALES	127,836,571	140,971,699	(13,135,126)	(9.3)	2,514,087	2,772,292	(258,205)	(9.3)	5.0848	5.0850	(0.0002)	0.0
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00122	127,992,532	141,304,392	(13,311,860)	(9.4)	2,514,087	2,772,292	(258,205)	(9.3)	5.0910	5.0970	(0.0060)	(0.1)
28	PRIOR PERIOD TRUE-UP	10,263,267	10,263,265	2	0.0	2,514,087	2,772,292	(258,205)	(9.3)	0.4082	0.3702	0.0380	10.3
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	2,514,087	2,772,292	(258,205)	(9.3)	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	2,514,087	2,772,292	(258,205)	(9.3)	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	138,255,799	151,567,657	(13,311,858)	(8.8)	2,514,087	2,772,292	(258,205)	(9.3)	5.4992	5.4672	0.0320	0.6
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									5.5032	5.4711	0.0321	0.6
32	GPIF	(248,341)	(248,339)			2,514,087	2,772,292			(0.0099)	(0.0090)	(0.0009)	10.0
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									5.493	5.462	0.031	0.6

*Line 15a. MWH Data for Infomational Purposes Only

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 23
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Thomas G. Foster - TGF-3T

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2012

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,488,511,720	1,605,097,411	(116,585,692)	(7.3)	34,149,677	34,526,745	(377,068)	(1.1)	4.3588	4.6489	(0.2901)	(6.2)
2	SPENT NUCLEAR FUEL DISPOSAL COST	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	COAL CAR INVESTMENT	51,948	12,108	39,840	329.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3a	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(23,333,391)	(118,285,714)	94,952,323	(80.3)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4a	ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	1,465,230,276	1,486,823,805	(21,593,529)	(1.5)	34,149,677	34,526,745	(377,068)	(1.1)	4.2906	4.3063	(0.0157)	(0.4)
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	137,112,849	242,324,799	(105,211,950)	(43.4)	2,785,407	3,979,414	(1,194,007)	(30.0)	4.9225	6.0895	(1.1670)	(19.2)
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	33,195	0	33,195	0.0	1,010	0	1,010	0.0	3.2867	0.0000	3.2867	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	14,141,777	14,547,829	(406,052)	(2.8)	282,986	262,834	20,152	7.7	4.9973	5.5350	(0.5377)	(9.7)
9	ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	188,576,313	184,587,542	3,990,771	2.2	3,938,055	3,804,882	133,173	3.5	4.7886	4.8513	(0.0627)	(1.3)
12	TOTAL COST OF PURCHASED POWER	339,866,135	441,460,170	(101,594,035)	(23.0)	7,007,457	8,047,130	(1,039,673)	(12.9)	4.8501	5.4859	(0.6358)	(11.6)
13	TOTAL AVAILABLE MWH					41,157,134	42,573,875	(1,416,741)	(3.3)				
14	FUEL COST OF ECONOMY SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
14a	GAIN ON ECONOMY SALES - 100% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
15	FUEL COST OF OTHER POWER SALES (SCH A6)	(1,426,863)	(2,314,799)	887,936	(38.4)	(50,186)	(58,457)	8,271	(14.2)	2.8431	3.9598	(1.1167)	(28.2)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6) *	(298,813)	(254,628)	(44,185)	17.4	(50,186)	(58,457)	8,271	(14.2)	0.5954	0.4356	0.1598	36.7
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16	FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17	FUEL COST OF STRATIFIED SALES	(50,711,317)	(101,826,174)	51,114,857	(50.2)	(1,495,674)	(2,173,200)	677,526	(31.2)	3.3905	4.6855	(1.2950)	(27.6)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(52,436,993)	(104,395,601)	51,958,608	(49.8)	(1,545,860)	(2,231,657)	685,797	(30.7)	3.3921	4.6779	(1.2858)	(27.5)
19	NET INADVERTENT AND WHEELED INTERCHANGE					106,639	0	106,639					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	1,752,659,418	1,823,888,374	(71,228,956)	(3.9)	39,717,914	40,342,218	(624,304)	(1.6)	4.4128	4.5210	(0.1082)	(2.4)
21	NET UNBILLED	10,775,627	(3,679,457)	14,455,084	(392.9)	(244,192)	(5,824)	(238,368)	4,092.9	0.0294	(0.0097)	0.0391	(403.1)
22	COMPANY USE	6,590,684	6,487,707	102,977	1.6	(149,355)	(144,000)	(5,355)	3.7	0.0180	0.0172	0.0008	4.7
23	T & D LOSSES	117,866,448	108,811,488	9,054,960	8.3	(2,671,032)	(2,406,109)	(264,923)	11.0	0.3216	0.2880	0.0336	11.7
						0.993	0.9769	0	2				
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,752,659,418	1,823,888,374	(71,228,956)	(3.9)	36,653,335	37,786,285	(1,132,950)	(3.0)	4.7817	4.8269	(0.0452)	(0.9)
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(12,823,010)	(42,014,673)	29,191,663	(69.5)	(271,878)	(873,034)	601,156	(68.9)	4.7165	4.8125	(0.0960)	(2.0)
26	JURISDICTIONAL KWH SALES	1,739,836,408	1,781,873,701	(42,037,293)	(2.4)	36,381,457	36,913,251	(531,794)	(1.4)	4.7822	4.8272	(0.0450)	(0.9)
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00122	1,742,109,320	1,786,078,923	(43,969,603)	(2.5)	36,381,457	36,913,251	(531,794)	(1.4)	4.7885	4.8386	(0.0501)	(1.0)
28	PRIOR PERIOD TRUE-UP	123,159,202	123,159,202	0	0.0	36,381,457	36,913,251	(531,794)	(1.4)	0.3385	0.3336	0.0049	1.5
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	36,381,457	36,913,251	(531,794)	(1.4)	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	36,381,457	36,913,251	(531,794)	(1.4)	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	1,865,268,522	1,909,238,125	(43,969,602)	(2.3)	36,381,457	36,913,251	(531,794)	(1.4)	5.1270	5.1722	(0.0452)	(0.9)
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									5.1307	5.1759	(0.0452)	(0.9)
32	GPIF	(2,980,090)	(2,980,090)			36,381,457	36,913,251			(0.0082)	(0.0081)	(0.0001)	98.8
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									5.123	5.168	(0.045)	(0.9)

*Line 15a. MWH Data for Infomational Purposes Only

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2012

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$98,398,929	114,052,660	($15,653,731)	(13.7)	$1,488,511,720	$1,605,097,411	($116,585,692)	(7.3)
1a.	NUCLEAR FUEL DISPOSAL COST	-	0	0	0.0	0	0	0	0.0
1b.	NUCLEAR DECOM & DECON	-	0	0	0.0	0	0	0	0.0
1c.	COAL CAR INVESTMENT	-	0	0	0.0	51,948	12,108	39,840	329.0
2 .	FUEL COST OF POWER SOLD	(52,724)	(25,495)	(27,229)	106.8	(1,426,863)	(2,314,799)	887,936	(38.4)
2a.	GAIN ON POWER SALES	(8,766)	(2,804)	(5,962)	212.6	(298,813)	(254,628)	(44,185)	17.4
3 .	FUEL COST OF PURCHASED POWER	8,622,088	17,969,695	(9,347,607)	(52.0)	137,112,849	242,324,799	(105,211,950)	(43.4)
3a.	ENERGY PAYMENTS TO QUALIFYING FAC.	24,687,666	17,373,434	7,314,231	42.1	188,578,313	184,587,542	3,990,771	2.2
3b.	DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	0.0	0	0	0	0.0
4 .	ENERGY COST OF ECONOMY PURCHASES	166,973	1,032,097	(865,124)	(83.8)	14,174,973	14,547,829	(372,856)	(2.6)
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	131,814,166	150,399,587	(18,585,421)	(12.4)	1,826,704,127	2,044,000,262	(217,296,135)	(10.6)
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(2,632,853)	(6,153,502)	3,520,649	(57.2)	(50,711,317)	(101,826,174)	51,114,857	(50.2)
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	(274,818)	0	(274,818)	0.0	(23,333,391)	(118,285,714)	94,952,323	(80.3)
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$128,906,495	$144,246,085	($15,339,590)	(10.6)	$1,752,659,418	$1,823,888,374	($71,228,956)	(3.9)
	FOOTNOTE: DETAIL OF LINE 6b ABOVE								
	INSPECTION & FUEL ANALYSIS REPORTS (Wholesale Portion)	$7	$0	$7		$232	$0	$232	
	INEFFICIENT USE OF BARTOW CC	0	0	0		0	0	0	
	UNIV.OF FL STEAM REVENUE ALLOCATION (Wholesale Portion)	830	0	830		8,820	0	8,820	
	ADJUSTMENT FOR NUCLEAR DECOM & DECON	0	0	0		0	0	0	
	TANK BOTTOM ADJUSTMENT	426,922	0	426,922		417,151	0	417,151	
	AERIAL SURVEY ADJUSTMENT (Coal Pile)	0	0	0		(657,920)	0	(657,920)	
	NEIL Replacement Power Reimbursement	0	0	0		(10,928,571)	(118,285,714)	107,357,143	
	E-Schedule Adjustment (2012)	0	0	0		0	0	0	
	(Gain)/Loss on Sale of #6 Oil	416,762	0	416,762		(474,571)	0	(474,571)	
	Prior Period Retail/Wholesale Allocation Correction for NEIL Refund	0	0	0		371,964	0	371,964	
	NET METER SETTLEMENT	0	0	0		13,921	0	13,921	
	St. George Island Emergency Fuel	0	0	0		0	0	0	
	Derivative Collateral Interest	2,789	0	2,789		509,735	0	509,735	
	Joint Owner CR3 Replacement Power (Capacity Factor Agreement)	(1,122,128)	0	(1,122,128)		(12,594,152)	0	(12,594,152)	
	SUBTOTAL LINE 6b SHOWN ABOVE	($274,818)	$0	($274,818)		($23,333,391)	($118,285,714)	$94,952,323	
B.	KWH SALES								
1 .	JURISDICTIONAL SALES	2,514,087,039	2,772,292,000	(258,204,961)	(9.3)	36,381,457,114	36,913,251,000	(531,793,886)	(1.4)
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	20,934,762	64,431,000	(43,496,238)	(67.5)	271,877,765	873,034,000	(601,156,235)	(68.9)
3 .	TOTAL SALES	2,535,021,801	2,836,723,000	(301,701,199)	(10.6)	36,653,334,879	37,786,285,000	(1,132,950,121)	(3.0)
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.17	97.73	1.44	1.5	99.26	97.69	1.57	1.6

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2012

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1.	JURISDICTIONAL FUEL REVENUE	$121,933,264	$143,165,657	($21,232,393)	(14.8)	$1,848,023,948	$1,906,260,179	($58,236,231)	(3.1)
2.	ADJUSTMENTS: PRIOR PERIOD ADJ	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(10,263,267)	(10,263,265)	(2)	0.0	(123,159,202)	(123,159,202)	(0)	0.0
2b.	INCENTIVE PROVISION	248,341	248,339	2	0.0	2,980,090	2,980,090	0	0.0
2c.	OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
3.	TOTAL JURISDICTIONAL FUEL REVENUE	111,918,338	133,150,732	(21,232,393)	(16.0)	1,727,844,836	1,786,081,067	(58,236,231)	(3.3)
4.	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	128,906,495	144,246,085	(15,339,590)	(10.6)	1,752,659,418	1,823,888,374	(71,228,956)	(3.9)
5.	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99.17	97.73	1.44	1.5	99.26	97.69	1.57	1.6
6.	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00122 LOSS MULTIPLIER)	127,992,532	141,304,392	(13,311,860)	0 (9.4)	1,742,109,320	1,786,078,923	(43,969,603)	(2.5)
7.	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	(16,074,194)	(8,153,661)	(7,920,533)	0 97.1	(14,264,485)	2,144	(14,266,629)	100.0
8.	INTEREST PROVISION FOR THE MONTH (LINE D10)	(19,240)	(138)	(19,101)	13,795.0	(337,717)	(64,145)	(273,573)	426.5
9.	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	(209,994,415)	(2,171,466)	(207,822,949)	9,570.6	(324,522,196)	(123,159,202)	(201,362,995)	163.5
10.	TRUE UP COLLECTED (REFUNDED)	10,263,267	10,263,265	2	0.0	123,159,202	123,159,202	0	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	(215,824,581)	(62,001)	(215,762,581)	348,001.1	(215,965,197)	(62,001)	(215,903,196)	348,227.9
12.	OTHER:	(1,753,018)				(1,612,403)		(1,612,403)	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	($217,577,600)	(62,001)	(217,515,599)	350,828.5	($217,577,600)	(62,001)	(217,515,599)	350,828.5
D.	INTEREST PROVISION								
1.	BEGINNING TRUE UP (LINE C9)	($209,994,415)	N/A	--	--				
2.	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	(217,558,360)	N/A	--	--				
3.	TOTAL OF BEGINNING & ENDING TRUE UP	(427,552,774)	N/A	--	--		NOT		
4.	AVERAGE TRUE UP (50% OF LINE D3)	(213,776,387)	N/A	--	--				
5.	INTEREST RATE - FIRST DAY OF REPORTING MONTH	0.160	N/A	--	--				
6.	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	0.050	N/A	--	--				
7.	TOTAL (LINE D5 + LINE D6)	0.210	N/A						
8.	AVERAGE INTEREST RATE (50% OF LINE D7)	0.105	N/A	--	--				
9.	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.009	N/A	--	--				
10.	INTEREST PROVISION (LINE D4 * LINE D9)	($19,240)	N/A	--	--				

A-3 Generating System Comparative Data Report

Progress Energy Florida, Inc.

Docket No. 130001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule: A3-1
Sheet 5 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	6,890,407	9,943,330	(3,052,923)	(30.7%)
2 - LIGHT OIL	18,829,066	38,048,499	(19,219,433)	(50.5%)
3 - COAL	407,895,600	461,150,639	(53,255,039)	(11.5%)
4 - GAS	1,054,896,646	1,095,954,942	(41,058,296)	(3.7%)
5 - NUCLEAR	0	0	0	0.0%
6	0	0	0	0.0%
7	0	0	0	0.0%
8 - TOTAL ($)	1,488,511,720	1,605,097,410	(116,585,690)	(7.3%)
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	45,476	62,429	(16,953)	(27.2%)
10 - LIGHT OIL	72,093	82,636	(10,543)	(12.8%)
11 - COAL	10,034,864	12,538,775	(2,503,911)	(20.0%)
12 - GAS	23,997,245	21,842,905	2,154,340	9.9%
13 - NUCLEAR	0	0	0	0.0%
14	0	0	0	0.0%
15	0	0	0	0.0%
16 - TOTAL (MWH)	34,149,677	34,526,745	(377,068)	(1.1%)
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	89,246	120,383	(31,137)	(25.9%)
18 - LIGHT OIL (BBL)	163,136	282,733	(119,597)	(42.3%)
19 - COAL (TON)	4,543,203	5,405,670	(862,467)	(16.0%)
20 - GAS (MCF)	187,422,970	168,513,099	18,909,871	11.2%
21 - NUCLEAR (MMBTU)	0	0	0	0.0%
22	0	0	0	0.0%
23	0	0	0	0.0%
BTUS BURNED (MILLION BTU)				
24 - HEAVY OIL	568,459	788,726	(220,267)	(27.9%)
25 - LIGHT OIL	925,480	1,638,733	(713,253)	(43.5%)
26 - COAL	106,599,484	127,530,287	(20,930,803)	(16.4%)
27 - GAS	189,832,950	168,513,099	21,319,851	12.7%
28 - NUCLEAR	0	0	0	0.0%
29	0	0	0	0.0%
30	0	0	0	0.0%
31 - TOTAL (MILLION BTU)	297,926,373	298,470,845	(544,472)	(0.2%)

A-3 Generating System Comparative Data Report

Progress Energy Florida, Inc.

Docket No. 130001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule: A3-2
Sheet 6 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATION MIX (% MWH)				
32 - HEAVY OIL	0.1	0.18	(0.0)	(26.4%)
33 - LIGHT OIL	0.2	0.24	(0.0)	(11.8%)
34 - COAL	29.4	36.32	(6.9)	(19.1%)
35 - GAS	70.3	63.26	7.0	11.1%
36 - NUCLEAR	0.0	0.00	0.0	0.0%
37	0.0	0.00	0.0	0.0%
38	0.0	0.00	0.0	0.0%
39 - TOTAL (% MWH)	100.0	100.0	0.0	0.0%
FUEL COST PER UNIT ($)				
40 - HEAVY OIL ($/BBL)	77.21	82.60	(5.39)	(6.5%)
41 - LIGHT OIL ($/BBL)	115.42	134.57	(19.15)	(14.2%)
42 - COAL ($/TON)	89.78	85.31	4.47	5.2%
43 - GAS ($/MCF)	5.63	6.50	(0.88)	(13.5%)
44 - NUCLEAR ($/MBTU)	0.00	0.00	0.00	0.0%
45	0.00	0.00	0.00	0.0%
46	0.00	0.00	0.00	0.0%
FUEL COST PER MILLION BTU ($/MILLION BTU)				
47 - HEAVY OIL	12.12	12.61	(0.49)	(3.9%)
48 - LIGHT OIL	20.35	23.22	(2.87)	(12.4%)
49 - COAL	3.83	3.62	0.21	5.8%
50 - GAS	5.56	6.50	(0.95)	(14.6%)
51 - NUCLEAR	0.00	0.00	0.00	0.0%
52	0.00	0.00	0.00	0.0%
53	0.00	0.00	0.00	0.0%
54 - SYSTEM ($/MBTU)	5.00	5.38	(0.38)	(7.1%)
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	12,500	12,634	(134)	(1.1%)
56 - LIGHT OIL	12,837	19,831	(6,993)	(35.3%)
57 - COAL	10,623	10,171	452	4.4%
58 - GAS	7,911	7,715	196	2.5%
59 - NUCLEAR	0	0	0	0.0%
60	0	0	0	0.0%
61	0	0	0	0.0%
62 - SYSTEM (BTU/KWH)	8,724	8,645	80	0.9%

A-3 Generating System Comparative Data Report

Progress Energy Florida, Inc.

Docket No. 130001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule: A3-3
Sheet 7 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)				
63 - HEAVY OIL	15.15	15.93	(0.78)	(4.9%)
64 - LIGHT OIL	26.12	46.04	(19.93)	(43.3%)
65 - COAL	4.06	3.68	0.39	10.5%
66 - GAS	4.40	5.02	(0.62)	(12.4%)
67 - NUCLEAR	0.00	0.00	0.00	0.0%
68	0.00	0.00	0.00	0.0%
69	0.00	0.00	0.00	0.0%
70 - SYSTEM (CENTS/KWH)	4.36	4.65	(0.29)	(6.2%)

Progress Energy Florida, Inc.
Schedule A6
Power Sold for the Month of
December 2012

Docket No. 130001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule A6

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(7)	(8)	(9)
Sold To	**Type & Schedule**	**Total KWH Sold (000)**	**KWH Wheeled from Other Systems (000)**	**KWH from Own Generation (000)**	**Fuel Cost C/KWH**	**Total Cost C/KWH**	**Fuel Adj Total $**	**Total Cost $**	**Gain on Sales $**
ESTIMATED		590		590	4.321	4.796	25,495.00	28,299.00	2,804.00
ACTUAL									
Florida Power & Light Company	Schedule C	49		49	3.708	3.751	1,816.92	1,837.99	21.07
City of New Smyma Beach, FL	CR-1	110		110	2.356	3.516	2,591.80	3,867.17	1,275.37
City of New Smyma Beach, FL	Schedule H	0		0	0.000	0.000	0.00	0.00	0.00
City of New Smyma Beach, FL	Schedule I	0		0	0.000	0.000	14,351.76	14,351.76	0.00
Reedy Creek Improvement District	CR-1	665		665	2.841	3.409	18,889.85	22,670.00	3,780.15
Seminole Electric Cooperative, Inc	CR-1	57		57	3.164	3.200	1,803.65	1,824.00	20.35
Tampa Electric Company	CR-1	49		49	2.482	3.071	1,216.00	1,505.00	289.00
The Energy Authority, Inc.	Schedule OS	517		517	2.331	2.985	12,053.67	15,433.92	3,380.25
Subtotal - Gain on Other Power Sales		**1,447**		**1,447**	**3.644**	**4.249**	**52,723.65**	**61,489.84**	**8,766.19**
CURRENT MONTH TOTAL		1,447		1,447	3.644	4.249	52,723.65	61,489.84	8,766.19
DIFFERENCE		857		857	(0.677)	(0.547)	27,228.65	33,190.84	5,962.19
DIFFERENCE %		145.25		145.25	(15.68)	(11.40)	106.80	117.29	212.63
CUMULATIVE ACTUAL		50,186		50,186	2.843	3.439	1,426,862.99	1,725,675.67	298,812.68
CUMULATIVE ESTIMATED		58,457		58,457	3.960	4.395	2,314,798.00	2,569,426.00	254,628.00
DIFFERENCE		(8,271)		(8,271)	(1.117)	(0.956)	(887,935.01)	(843,750.33)	44,184.68
DIFFERENCE %		(14.15)		(14.15)	(28.21)	(21.75)	(38.36)	(32.84)	17.35

REDACTED

PROGRESS ENERGY FLORIDA, INC.
SCHEDULE A12 - CAPACITY COSTS
FOR THE PERIOD JAN - DEC 2012

Docket No. 130001-EI
Witness: Foster
Exhibit No. (TGF-3T)
Schedule A12
Sheet 9 of 9

	Counterparty	Type	MW	Start Date - End Date	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YTD
1	Auburndale Power Partners, L.P. (AUBRDLFC)	QF	17.00	1/1/95 - 12/31/13	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	775,370	9,304,440
2	Auburndale Power Partners, L.P. (AUBSET)	QF	114.18	8/1/94 - 12/31/13	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	3,437,396	41,248,749
3	Lake County (LAKCOUNT)	QF	12.75	1/1/95 - 6/30/14	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	726,878	8,722,530
4	Lake Cogen Limited (LAKORDER)	QF	110.00	7/1/93 - 7/31/13	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	3,553,265	42,639,181
5	Metro-Dade County (METRDADE)	QF	43.00	11/1/91 - 11/30/13	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	1,334,720	16,016,640
6	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	2,813,601	33,763,215
7	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	2,682,226	2,675,846	2,676,295	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	2,740,784	32,701,424
8	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	1,311,230	15,734,760
9	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	3,121,298	37,455,570
10	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	5,431,880	65,182,554
11	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,349
12	UPS Purchase (414 total mw) - Southern	Other	414	7/19/88 - 5/31/10	0	0	(230,855)	0	0	0	0	0	(16,836)	0	0	0	(247,691)
13	Southern purchase - Scherer	Other	74	6/1/10 - 5/31/16	1,666,586	1,661,304	1,663,945	1,663,945	2,237,943	1,558,717	1,718,299	1,705,138	1,710,820	1,711,718	1,709,996	1,711,113	20,719,523
14	Southern purchase - Franklin	Other	350	6/1/10 - 5/31/16	2,163,000	2,163,000	2,163,000	2,768,640	3,289,165	2,291,019	3,063,230	3,006,201	3,361,856	2,999,467	3,027,032	3,030,258	33,325,867
15	Retail Wheeling				(2,932)	(1,199)	(455)	(3,033)	(1,120)	(2,803)	(12,128)	(2,527)	(1,328)	(2,613)	(2,034)	(995)	(33,167)
16	Levy Projected Expense				6,337,833	7,810,874	6,296,044	6,291,658	6,519,755	6,194,943	6,226,912	6,313,327	7,128,277	7,180,333	7,034,232	7,022,525	80,356,713
17	CR-3 Projected Expense				465,111	465,187	465,298	465,445	465,628	465,848	466,105	466,399	466,731	467,101	467,510	467,958	5,594,321
	SUBTOTAL				36,618,406	38,081,595	36,339,854	37,234,021	38,558,737	36,555,091	37,509,783	37,535,904	38,696,886	38,403,372	38,284,102	38,278,226	452,095,978

Confidential Capacity Contracts (Aggregated):

	Purchases/Sales (Net)	Other	MW	Contracts													
	Chattahoochee Capacity Purchase	1	[redacted]		12,500	11,513	13,084	12,634	12,366	12,634	12,769	12,500	12,231	12,769	12,231	12,769	150,000
	Reliant - Vandolah Capacity Purchase	1			1,418,840	1,418,840	1,014,360	1,014,360	1,418,840	5,599,810	5,818,316	5,840,887	2,711,658	1,916,830	2,014,083	2,942,812	33,129,635
	Schedule H Capacity Sales-NSB	1			(11,552)	(10,807)	(11,552)	(11,179)	(11,307)	(10,942)	(11,307)	(11,307)	(10,942)	(11,307)	(14,468)	(14,792)	(141,461)
	Shady Hills Tolling	1			1,965,615	1,965,615	1,404,011	1,362,100	1,908,900	3,879,900	3,879,900	3,879,900	1,810,620	1,363,500	1,363,500	1,969,380	26,752,942
	Total		837.25	4	3,385,403	3,385,161	2,419,903	2,377,915	3,328,799	9,481,402	9,699,678	9,721,980	4,523,567	3,281,793	3,375,346	4,910,168	59,891,116
	TOTAL				40,003,809	41,466,756	38,759,757	39,611,937	41,887,536	46,036,493	47,209,461	47,257,884	43,220,453	41,685,165	41,659,449	43,188,394	511,987,094

Docket No. 130001-EI
Witness: Foster
Exhibit No. (TGF-4T)
Sheet 1 of 1

Capital Structure and Cost Rates Applied to Capital Projects
Progress Energy Florida
For the period of January through December 2012

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 2,945,782	46.74%	10.50%	4.91%
Long Term Debt	2,846,460	45.17%	6.18%	2.79%
Short Term Debt	41,666	0.66%	3.72%	0.03%
Preferred Stock	21,456	0.34%	4.51%	0.02%
Customer Deposits - Active	145,590	2.31%	5.95%	0.14%
Customer Deposits - Inactive	1,472	0.02%	0.00%	0.00%
Deferred Tax	420,125	6.67%	0.00%	0.00%
Deferred Tax (FAS 109)	(124,168)	-1.97%	0.00%	0.00%
ITC	3,896	0.06%	8.36%	0.01%
	6,302,278	100.00%		7.88%

Total Debt	2.95%
Total Equity	4.93%

Reference: Docket No. 090079-EI, PSC Order No. 10-0131-FOF-EI, page 172

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 24
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Thomas G. Foster - TGF-4T

Docket 130001-EI
Exhibit No. ____(TGF-2)
Part 1

PROGRESS ENERGY FLORIDA

FUEL COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2013

REDACTED

Schedule E1-B – Calculation of Estimated True-up

Schedule E2 – Fuel Cost Recovery Clause Calculation by Month

Schedule E3 – Generating System Comparative Data

Schedule E4 – System Net Generation & Fuel Cost by Month

Schedule E5 – Inventory Analysis

Schedule E6 – Fuel Cost of Power Sold

Schedule E7 – Purchased Power

Schedule E8 – Energy Payments to Qualifying Facilities

Schedule E9 – Economy Energy Purchases

Capital Structure and Cost Rates Applied to Capital Projects
(Order No. PSC-12 0425-PAA-EU)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 25
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Thomas G. Foster - TGF-2

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2013

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 105,743,586	$ 97,112,812	$ 110,347,311	$ 117,890,107	$ 126,232,404	$ 147,371,377	$ 704,697,597
	2	Fuel Cost of Power Sold	(3,047,976)	(2,326,177)	(2,554,581)	(3,037,857)	(5,011,053)	(4,283,713)	(20,261,358)
	3	Fuel Cost of Purchased Power	4,993,222	7,400,788	8,066,615	11,342,391	10,281,566	19,239,698	61,324,281
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	19,749,624	16,442,524	18,086,260	16,205,598	18,334,050	19,697,765	108,515,841
	4	Energy Cost of Economy Purchases	236,354	157,429	583,403	943,332	2,291,585	3,281,318	7,493,422
	5	Adjustments to Fuel Cost	(14,542,710)	(11,782,902)	(12,003,796)	(12,497,267)	(507,889,089)	(11,979,214)	(570,694,978)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	113,132,100	107,004,475	122,525,232	130,846,304	(355,760,537)	173,327,232	291,074,805
B	1	Jurisdictional KWH Sales	2,608,843	2,578,190	2,542,535	2,678,410	3,007,039	3,332,396	16,747,413
	2	Non-Jurisdictional KWH Sales	19,110	16,403	14,531	17,654	13,320	20,035	101,053
	3	TOTAL SALES (Lines B1 + B2)	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	16,848,466
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	93,290,375	92,122,713	90,898,588	96,136,174	109,403,698	122,302,252	604,153,799
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(72,683,454)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(747,786)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	81,051,835	79,884,173	78,660,048	83,897,634	97,165,158	110,063,712	530,722,559
	4	Fuel & Net Power Transactions (Line A6)	113,132,100	107,004,475	122,525,232	130,846,304	(355,760,537)	173,327,232	291,074,805
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	112,443,249	106,489,842	122,009,579	130,190,797	(354,726,484)	172,545,699	288,952,682
	6	Over/(Under) Recovery (Line C3 - Line C5)	(31,391,414)	(26,605,669)	(43,349,531)	(46,293,163)	451,891,642	(62,481,987)	241,769,878
	7	Interest Provision	(13,633)	(19,529)	(21,369)	(20,997)	(5,103)	6,086	(74,542)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(31,405,047)	(26,625,199)	(43,370,900)	(46,314,160)	451,886,539	(62,475,899)	241,695,335
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	12,113,909	24,227,818	36,341,727	48,455,636	60,569,545	72,683,454	72,683,454
	11	Subtotal Prior Period True-up	(205,463,691)	(193,349,782)	(181,235,873)	(169,121,964)	(157,008,055)	(144,894,146)	(144,894,146)
	12	Regulatory Accounting Adjustment	-	-	(229,070)	-	37,080	-	(191,990)
	13	TOTAL TRUE-UP BALANCE	($236,868,738)	(251,380,027)	($282,866,088)	($317,066,339)	$146,971,190	$96,609,199	$96,609,199

CALCULATION OF ESTIMATED TRUE-UP
(5 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2013

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 145,250,812	$ 150,607,717	$ 136,985,940	$ 114,538,238	$ 107,075,208	$ 108,923,607	$ 1,468,079,120
	2	Fuel Cost of Power Sold	(5,569,460)	(5,527,090)	(5,386,128)	(4,969,913)	(3,255,686)	(2,375,290)	(47,344,905)
	3	Fuel Cost of Purchased Power	23,957,592	25,094,990	21,710,075	18,555,272	9,554,987	8,498,016	166,696,213
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	18,004,359	13,089,077	12,644,871	11,903,930	12,657,284	15,780,883	192,576,244
	4	Energy Cost of Economy Purchases	1,756,060	1,775,447	1,776,669	1,742,573	915,761	706,536	16,166,498
	5	Adjustments to Fuel Cost	(10,617,565)	(10,821,916)	(10,826,271)	(10,828,450)	(10,827,360)	(10,816,477)	(635,633,016)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
B	1	Jurisdictional KWH Sales	3,583,405	3,748,970	3,752,239	3,277,587	2,841,165	2,732,348	36,683,127
	2	Non-Jurisdictional KWH Sales	18,864	21,241	22,661	20,547	17,439	14,034	215,839
	3	TOTAL SALES (Lines B1 + B2)	3,602,269	3,770,211	3,774,900	3,298,134	2,858,604	2,746,382	36,898,966
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.48%	99.44%	99.40%	99.38%	99.39%	99.49%	99.42%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	132,431,293	138,550,051	138,670,863	121,129,229	105,000,455	100,978,923	1,340,914,612
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,913)	(145,366,912)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(1,495,572)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	120,192,753	126,311,511	126,432,323	108,890,689	92,761,915	88,740,380	1,194,052,129
	4	Fuel & Net Power Transactions (Line A6)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	171,941,900	173,502,467	156,197,670	130,325,007	115,585,027	118,270,053	1,154,774,805
	6	Over/(Under) Recovery (Line C3 - Line C5)	(51,749,146)	(47,190,956)	(29,765,347)	(21,434,318)	(22,823,112)	(29,529,674)	39,277,324
	7	Interest Provision	3,842	1,974	656	(18)	(519)	(1,222)	(69,830)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(51,745,304)	(47,188,981)	(29,764,691)	(21,434,336)	(22,823,632)	(29,530,897)	39,207,494
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	84,797,363	96,911,272	109,025,181	121,139,090	133,252,999	145,366,912	145,366,912
	11	Subtotal Prior Period True-up	(132,780,237)	(120,666,328)	(108,552,419)	(96,438,510)	(84,324,601)	(72,210,688)	(72,210,688)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	(191,990)
	13	TOTAL TRUE-UP BALANCE	$56,977,803	$21,902,731	$4,251,949	($5,068,478)	($15,778,200)	($33,195,183)	($33,195,183)

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
Duke Energy Florida
Estimated for the Period of : January through December 2013

		DOLLARS				MWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %
1	Fuel Cost of System Net Generation (E3)	1,468,079,120	1,361,604,286	106,474,833	8%	33,103,741	33,752,262	(648,521)	-2%	4.435	4.034	0.401	10%
2	Spent Nuclear Fuel Disposal Cost	0	0	-	0%	0	0	-	0%	0.000	0.000	0.000	0%
3	Coal Car Investment	0	0	-	0%			-		0.000	0.000	0.000	
4	Adjustment to Fuel Cost	(635,633,018)	(456,990,441)	(178,642,576)	0%			-		0.000	0.000	0.000	
5	TOTAL COST OF GENERATED POWER	832,446,102	904,613,845	(72,167,743)	-8%	33,103,741	33,752,262	(648,521)	-2%	2.515	2.680	-0.165	-6%
6	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	166,696,213	197,756,948	(31,060,735)	-16%	3,014,077	3,758,406	(744,329)	-20%	5.531	5.262	0.269	5%
				-				-		0.000	0.000	0.000	
7	Energy Cost of Economy Purchases (E9)	16,166,498	11,096,755	5,069,743	46%	275,451	182,273	93,178	51%	5.869	6.088	-0.219	
8	Payments to Qualifying Facilities (E8)	192,576,244	161,948,287	30,627,957	19%	4,034,436	3,479,980	554,456	16%	4.773	4.654	0.120	3%
9	TOTAL COST OF PURCHASED POWER	375,438,955	370,801,990	4,636,965	1%	7,323,963	7,420,659	(96,696)	-1%	5.126	4.997	0.129	3%
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)			-		40,427,704	41,172,921	(745,217)	-2%	0.000	0.000	0.000	
11	Fuel Cost of Economy Sales (E6)	(2,238,922)	(2,813,022)	574,100	-20%	(64,589)	(78,416)	13,827	-18%	3.466	3.587	-0.121	-3%
11a	Gain on Economy Sales (E6)	(509,875)	(365,693)	(144,182)	39%	(64,589)	(78,416)	13,827	-18%	0.789	0.466	0.323	69%
12	Fuel Cost of Stratified Sales (E6)	(44,596,108)	(36,175,371)	(8,420,738)	23%	(1,182,948)	(1,209,795)	26,847	-2%	3.770	2.990	0.780	26%
13	TOTAL FUEL COST AND GAINS OF POWER SALES (LINES 11 + 11a + 12)	(47,344,905)	(39,354,086)	(7,990,820)	20%	(1,247,537)	(1,288,211)	40,674	-3%	3.795	3.055	0.740	24%
14	Net Inadvertent Interchange					113,112		113,112					
15	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 9 + 13 + 14)	1,160,540,151	1,236,061,749	(75,521,598)	-6%	39,293,279	39,884,710	(591,431)	-1%	2.954	3.099	-0.146	-5%
16	Net Unbilled					157,820	(35,330)	193,150	-547%	0.000	0.000	0.000	
17	Company Use					(146,735)	(144,000)	(2,735)	2%	0.000	0.000	0.000	
18	T & D Losses					(2,405,398)	(2,208,703)	(196,695)	9%	0.000	0.000	0.000	
19	SYSTEM KWH SALES	1,160,540,151	1,236,061,749	(75,521,598)	-6%	36,898,966	37,496,677	(597,711)	-2%	3.145	3.296	-0.151	-5%
20	Wholesale KWH Sales	(7,453,516)	(2,856,630)	(4,606,886)	161%	(215,839)	(113,303)	(102,536)	90%	3.458	2.521	0.937	37%
21	Jurisdictional KWH Sales	1,153,076,636	1,233,205,120	(80,128,484)	-6%	36,683,127	37,383,374	(700,247)	-2%	3.143	3.299	-0.155	-5%
21a	Jurisdictional Loss Multiplier	1.0015	1.00122	0	0%	1.0015	1.00122	0	0%				
22	Jurisdictional Sales Adjusted for Line Losses	1,154,774,804	1,234,709,629	(79,934,825)	-6%	36,683,127	37,383,374	(700,247)	-2%	3.148	3.303	-0.155	-5%
23	TRUE-UP **	217,577,600	145,366,912	72,210,688	50%	36,683,127	37,383,374	(700,247)	-2%	0.593	0.389	0.204	53%
24	TOTAL JURISDICTIONAL FUEL COST	1,372,352,404	1,380,076,540	(7,724,137)	-1%	36,683,127	37,383,374	(700,247)	-2%	3.741	3.692	0.049	1%
25	Revenue Tax Factor	988,094	993,655	(5,561)	-1%								
26	Fuel Factor Adjusted for Taxes	1,373,340,497	1,381,070,196	(7,729,698)	-1%	36,683,127	37,383,374	(700,247)	-2%	3.744	3.694	0.049	1%
27	GPIF **	1,495,572	1,495,572	-	0%	36,683,127	37,383,374	(700,247)	-2%	0.004	0.004	0.000	2%
28	Fuel Factor Adjusted for Taxes Including GPIF	1,374,836,069	1,382,565,768	(7,729,698)	-1%	36,683,127	37,383,374	(700,247)	-2%	3.748	3.698	0.050	1%
29	FUEL FACTOR ROUNDED TO NEAREST .001 ¢/KWH									3.748	3.698	0.050	1%

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2013

			Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Estimated Jul-13	Estimated Aug-13	Estimated Sep-13	Estimated Oct-13	Estimated Nov-13	Estimated Dec-13	TOTAL
1	Fuel Cost of System Net Generation		$105,743,586	$97,112,812	$110,347,311	$117,990,107	$120,232,404	$147,371,377	$145,250,812	$150,607,717	$139,985,940	$114,538,238	$107,075,208	$108,923,607	$1,466,079,120
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(14,542,710)	(11,782,902)	(12,003,796)	(12,497,287)	(507,889,089)	(11,979,214)	(10,817,585)	(10,821,916)	(10,826,271)	(10,828,450)	(10,827,380)	(10,816,477)	(635,633,018)
2	Fuel Cost of Power Sold		(62,075)	(145,944)	(270,085)	(321,292)	(80,886)	(204,859)	(484,794)	(283,697)	(55,842)	(241,586)	(46,452)	(31,410)	(2,238,922)
2a	Gains on Power Sales		(11,835)	(30,429)	(48,239)	(69,128)	(14,883)	(73,067)	(101,807)	(61,676)	(11,727)	(50,733)	(9,756)	(6,596)	(509,875)
2b	Fuel Cost of Stratified Sales		(2,974,066)	(2,149,805)	(2,236,257)	(2,627,437)	(4,915,305)	(4,005,767)	(4,982,859)	(5,171,717)	(5,318,559)	(4,877,594)	(3,199,458)	(2,337,284)	(44,596,108)
3	Fuel Cost of Purchased Power (Excl Economy)		4,993,222	7,400,788	8,066,615	11,342,391	10,281,566	19,239,698	23,957,592	25,094,990	21,710,075	18,555,272	9,554,987	9,469,016	166,596,213
3a	Energy Payments to Qualifying Facilities		19,749,624	16,442,524	18,086,280	16,205,598	18,334,050	19,697,765	18,004,359	13,089,077	12,644,871	11,903,930	12,657,284	15,760,883	192,578,244
4	Energy Cost of Economy Purchases		236,354	157,429	583,403	943,332	2,291,585	3,281,318	1,756,060	1,775,447	1,776,669	1,742,573	915,791	705,536	16,165,498
5	Total System Fuel & Net Power Transactions		$113,132,100	$107,004,475	$122,525,232	$130,846,304	($355,760,537)	$173,327,232	$172,581,798	$174,218,225	$159,605,155	$130,941,850	$118,120,243	$118,668,275	$1,160,540,151
6	Jurisdictional MWH Sold		2,608,843	2,578,190	2,542,535	2,878,410	3,007,039	3,332,396	3,583,405	3,748,970	3,752,239	3,277,587	2,841,165	2,732,348	36,883,127
7	Jurisdictional % of Total Sales		99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.46%	99.44%	99.40%	99.38%	99.39%	99.49%	99.42%
8	Jurisdictional Fuel & Net Power Transactions		112,306,235	106,330,346	121,826,838	129,995,803	(354,195,191)	172,287,268	171,684,373	173,242,603	155,963,724	130,129,812	115,411,809	118,092,814	1,153,076,936
9	Jurisdictional Loss Multiplier		1.00122	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150
10	Jurisdictional Fuel & Net Power Transactions		112,443,249	106,489,842	122,008,579	130,190,797	(354,726,484)	172,545,699	171,941,900	173,502,467	156,197,670	130,325,007	115,585,027	118,270,053	1,154,774,805
11	Adjusted System Sales	MWH	2,627,652	2,594,583	2,557,065	2,898,064	3,020,359	3,352,431	3,602,269	3,770,211	3,774,900	3,298,134	2,856,604	2,746,382	36,898,965
12	System Cost per KWH Sold	c/kwh	4.3050	4.1242	4.7917	4.8533	-11.7787	5.1703	4.7909	4.5209	4.1565	3.9702	4.0621	4.3220	3.1452
13	Jurisdictional Loss Multiplier	x	1.00122	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.00150
14	Jurisdictional Cost per KWH Sold	c/kwh	4.3101	4.1304	4.7987	4.8507	-11.7965	5.1778	4.7983	4.5280	4.1628	3.9762	4.0682	4.3285	3.1480
15	Prior Period True-Up	+	0.8950	0.7033	0.7131	0.5770	0.6030	0.5441	0.5060	0.4836	0.4832	0.5532	0.6382	0.6636	0.6931
16	Total Jurisdictional Fuel Expense	c/kwh	5.0051	4.8337	5.5119	5.5277	-11.1936	5.7219	5.3043	5.1116	4.8460	4.5294	4.7064	4.9921	3.7411
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	5.0087	4.8372	5.5158	5.5417	-11.2016	5.7260	5.3081	5.1153	4.8494	4.5327	4.7098	4.9957	3.7438
19	GPIF	+	0.0046	0.0048	0.0049	0.0047	0.0041	0.0037	0.0033	0.0033	0.0033	0.0038	0.0044	0.0046	0.0041
20	Total Recovery Factor (rounded .001)	c/kwh	5.013	4.842	5.521	5.546	-11.197	5.730	5.312	5.119	4.853	4.537	4.714	5.000	3.748

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2013

			Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		994,063	541,010	4,037,714	5,562,175	2,437,288	54,784	13,627,034
2	LIGHT OIL		1,168,288	1,644,322	1,077,464	1,352,253	1,599,091	2,003,180	8,844,597
3	COAL		28,138,148	28,312,028	30,273,745	42,151,769	43,648,466	41,861,777	214,385,933
4	GAS		75,443,087	66,615,453	74,958,388	68,823,910	78,547,559	103,451,635	467,840,033
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	105,743,586	97,112,812	110,347,311	117,890,107	126,232,404	147,371,377	704,697,597
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		6,042	3,603	30,022	42,596	16,950	266	99,479
9	LIGHT OIL		4,553	9,282	4,359	4,905	6,290	7,679	37,068
10	COAL		713,071	725,070	731,307	1,077,177	1,054,342	987,200	5,288,167
11	GAS		1,622,428	1,456,397	1,669,548	1,498,718	1,774,593	2,173,223	10,194,906
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,346,093	2,194,352	2,435,235	2,623,396	2,852,175	3,168,368	15,619,620
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	12,588	7,205	53,780	74,020	32,433	627	180,653
16	LIGHT OIL	BBL	9,306	15,500	8,402	11,026	13,004	17,314	74,552
17	COAL	TON	325,923	331,764	330,724	491,918	483,335	448,177	2,411,841
18	GAS	MCF	12,758,401	11,475,634	13,246,727	11,359,331	13,586,022	16,641,086	79,067,201
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		76,467	43,897	327,741	451,158	197,682	3,822	1,100,766
22	LIGHT OIL		54,073	88,743	48,949	63,837	75,736	100,205	431,544
23	COAL		7,606,159	7,687,358	7,687,495	11,413,485	11,251,461	10,340,044	55,986,001
24	GAS		12,911,109	11,619,001	13,427,882	11,504,892	13,765,451	16,861,050	80,089,386
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	20,647,808	19,439,000	21,492,066	23,433,372	25,290,330	27,305,122	137,607,697
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.26%	0.16%	1.23%	1.62%	0.59%	0.01%	0.64%
29	LIGHT OIL		0.19%	0.42%	0.18%	0.19%	0.22%	0.24%	0.24%
30	COAL		30.39%	33.04%	30.03%	41.06%	36.97%	31.16%	33.86%
31	GAS		69.15%	66.37%	68.56%	57.13%	62.22%	68.59%	65.27%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	78.97	75.09	75.08	75.14	75.15	87.38	75.43
36	LIGHT OIL	$/BBL	125.54	106.09	128.24	122.64	122.97	115.70	118.64
37	COAL	$/TON	86.33	85.34	91.54	85.69	90.31	93.40	88.89
38	GAS	$/MCF	5.91	5.80	5.66	6.06	5.78	6.22	5.92
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		13.00	12.32	12.32	12.33	12.33	14.34	12.38
42	LIGHT OIL		21.61	18.53	22.01	21.18	21.11	19.99	20.50
43	COAL		3.70	3.68	3.94	3.69	3.88	4.05	3.83
44	GAS		5.84	5.73	5.58	5.98	5.71	6.14	5.84
45	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	5.12	5.00	5.13	5.03	4.99	5.40	5.12
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		12,657	12,182	10,917	10,592	11,663	14,350	11,065
49	LIGHT OIL		11,877	9,560	11,229	13,014	12,041	13,049	11,642
50	COAL		10,667	10,602	10,512	10,596	10,672	10,474	10,587
51	GAS		7,958	7,978	8,043	7,676	7,757	7,759	7,856
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,801	8,859	8,825	8,932	8,867	8,618	8,810
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		16.45	15.01	13.45	13.06	14.38	20.57	13.70
56	LIGHT OIL		25.66	17.71	24.72	27.57	25.42	26.09	23.86
57	COAL		3.95	3.90	4.14	3.91	4.14	4.24	4.05
58	GAS		4.65	4.57	4.49	4.59	4.43	4.76	4.59
59	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	4.51	4.43	4.53	4.49	4.43	4.65	4.51

Duke Energy Florida
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January through December 2013

			Estimated Jul-13	Estimated Aug-13	Estimated Sep-13	Estimated Oct-13	Estimated Nov-13	Estimated Dec-13	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		486,077	503,374	290,704	100,579	0	0	15,007,768
2	LIGHT OIL		4,195,789	3,866,221	1,977,324	1,742,390	891,552	904,625	22,422,499
3	COAL		45,455,587	44,701,655	41,506,568	31,283,493	40,001,693	37,499,886	454,834,815
4	GAS		95,113,359	101,536,467	93,211,344	81,411,776	66,181,963	70,519,096	975,814,038
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	145,250,812	150,607,717	136,985,940	114,538,238	107,075,208	108,923,607	1,468,079,120
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		3,229	3,401	1,957	700	0	0	108,766
9	LIGHT OIL		9,768	9,427	2,827	2,803	21	2	61,916
10	COAL		1,118,527	1,107,335	1,027,602	784,471	861,351	1,005,903	11,193,356
11	GAS		2,179,931	2,325,718	2,128,912	1,850,853	1,498,944	1,560,439	21,739,703
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,311,455	3,445,881	3,161,298	2,638,827	2,360,316	2,566,344	33,103,741
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	6,157	6,377	3,683	1,274	0	0	198,144
16	LIGHT OIL	BBL	31,875	29,213	14,642	12,821	6,245	6,376	175,723
17	COAL	TON	509,105	505,582	470,298	366,584	389,211	448,818	5,101,439
18	GAS	MCF	17,129,241	18,537,363	16,610,266	14,615,114	11,302,217	11,910,879	169,172,281
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		40,343	41,779	24,128	8,348	0	0	1,215,364
22	LIGHT OIL		184,740	169,305	84,854	74,306	36,203	35,954	1,017,907
23	COAL		11,991,381	11,884,164	11,043,354	8,545,386	9,070,586	10,440,871	118,961,743
24	GAS		17,129,241	18,537,363	16,610,266	14,615,114	11,302,217	11,910,879	170,194,466
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	29,345,705	30,632,611	27,762,602	23,243,154	20,409,006	22,388,704	291,389,480
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.10%	0.10%	0.06%	0.03%	0.00%	0.00%	0.33%
29	LIGHT OIL		0.30%	0.27%	0.09%	0.11%	0.00%	0.00%	0.19%
30	COAL		33.78%	32.14%	32.51%	29.73%	36.49%	39.20%	33.81%
31	GAS		65.83%	67.49%	67.34%	70.14%	63.51%	60.80%	65.67%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	78.95	78.94	78.93	78.95	0.00	0.00	75.74
36	LIGHT OIL	$/BBL	131.63	132.35	135.04	135.91	142.76	141.88	127.60
37	COAL	$/TON	89.29	88.42	88.26	85.34	102.78	83.55	89.16
38	GAS	$/MCF	5.55	5.48	5.61	5.57	5.86	5.92	5.77
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		12.05	12.05	12.05	12.05	0.00	0.00	12.35
42	LIGHT OIL		22.71	22.84	23.30	23.45	24.63	24.48	22.03
43	COAL		3.79	3.76	3.76	3.66	4.41	3.59	3.82
44	GAS		5.55	5.48	5.61	5.57	5.86	5.92	5.73
45	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	4.95	4.92	4.93	4.93	5.25	4.87	5.04
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		12,494	12,284	12,329	11,926	0	0	11,174
49	LIGHT OIL		18,913	17,960	30,016	26,510	1,723,949	18,476,828	16,440
50	COAL		10,721	10,732	10,747	10,893	10,531	10,380	10,628
51	GAS		7,858	7,971	7,802	7,896	7,540	7,633	7,829
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,862	8,890	8,782	8,808	8,647	8,724	8,802
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		15.05	14.80	14.85	14.37	0.00	0.00	13.80
56	LIGHT OIL		42.95	41.01	69.94	62.16	4,245.49	45,231.25	36.21
57	COAL		4.06	4.04	4.04	3.99	4.64	3.73	4.06
58	GAS		4.36	4.37	4.38	4.40	4.42	4.52	4.49
59	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	4.39	4.37	4.33	4.34	4.54	4.24	4.43

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-13

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	149,202	53.5	92.74	55.8	10,812	COAL	65,165 TONS	24.76	1,613,164	7,679,256	5.15
3 CRYSTAL RIVER	2	494	190,293	51.8	92.14	54.6	10,683	COAL	82,123 TONS	24.76	2,032,950	9,638,345	5.07
4 CRYSTAL RIVER	4	722	399,294	74.3	92.57	76.7	10,621	COAL	163,865 TONS	23.06	4,240,825	14,286,971	3.58
5 CRYSTAL RIVER	5	700	379,738	72.9	93.71	76.1	10,809	COAL	177,952 TONS	23.06	4,104,432	13,849,015	3.65
6 ANCLOTE	1	501	0	0.0	90.90	32.9	0	HEAVY OIL	0 BBLS		0	0	0.00
7 ANCLOTE	2	510	3,229	7.9	94.25	27.4	12,494	HEAVY OIL	6,157 BBLS	6.55	40,343	486,077	15.05
8 SUWANNEE	1	30	0	0.0	30.00	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	93.23	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	94.64	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11 ANCLOTE	1	501	54,843	14.7	0.00	32.9	12,282	GAS	673,571 MCF	1.00	673,571	3,848,145	7.02
12 ANCLOTE	2	510	26,854	7.9	0.00	27.4	12,493	GAS	335,496 MCF	1.00	335,496	2,308,213	8.60
13 AVON PARK	1-2	49	653	1.9	82.42	50.1	16,360	GAS	10,683 MCF	1.00	10,683	68,162	10.44
14 BARTOW	1-4	177	3,603	2.8	97.26	24.8	14,066	GAS	50,679 MCF	1.00	50,679	269,844	7.49
15 BARTOW CC	1	1,159	709,290	82.3	95.09	86.2	7,244	GAS	5,138,264 MCF	1.00	5,138,264	27,889,557	3.93
16 DEBARY	1-10	645	19,069	4.3	95.90	10.8	13,177	GAS	251,272 MCF	1.00	251,272	1,339,552	7.02
17 HIGGINS	1-4	113	3,649	4.3	88.87	21.7	16,357	GAS	59,687 MCF	1.00	59,687	330,376	9.05
18 HINES CC	1-4	1,912	1,126,242	79.2	94.03	21.2	7,254	GAS	8,169,688 MCF	1.00	8,169,688	45,403,230	4.03
19 INT CITY	1-14	987	58,047	8.5	95.23	6.8	13,115	GAS	761,331 MCF	1.00	761,331	4,254,930	7.33
20 SUWANNEE	1	52	12,886	33.3	95.18	51.0	13,946	GAS	179,712 MCF	1.00	179,712	1,062,347	8.24
21 SUWANNEE	2	50	13,206	35.5	94.84	38.1	14,290	GAS	188,712 MCF	1.00	188,712	1,054,590	7.99
22 SUWANNEE	3	51	27,844	73.4	98.39	77.3	11,996	GAS	334,005 MCF	1.00	334,005	1,765,152	6.34
23 TIGER BAY CC	1	204	90,697	59.8	86.11	95.0	7,328	GAS	664,601 MCF	1.00	664,601	3,807,286	4.20
24 UNIV OF FLA. CC	1	46	33,048	96.6	96.71	97.9	9,427	GAS	311,540 MCF	1.00	311,540	1,711,575	5.18
25 AVON PARK	1-2	49	34	1.9	82.42	701.0	18,705	LIGHT OIL	110 BBLS	5.78	636	14,611	42.97
26 BARTOW	1-4	177	90	2.8	97.26	521.6	16,944	LIGHT OIL	263 BBLS	5.80	1,525	34,640	38.49
27 BAYBORO	1-4	174	1,869	1.4	94.68	17.3	14,976	LIGHT OIL	4,829 BBLS	5.80	27,991	652,705	34.92
28 DEBARY	1-10	645	1,597	4.3	95.90	57.2	15,150	LIGHT OIL	4,175 BBLS	5.79	24,194	556,461	34.84
29 HIGGINS	1-4	113	0	0.0	88.87	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	94.03	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31 INT CITY	1-14	987	4,643	8.5	95.23	3.1	15,327	LIGHT OIL	12,278 BBLS	5.80	71,163	1,614,007	34.76
32 RIO PINAR	1	12	8	144.4	95.16	66.7	18,625	LIGHT OIL	26 BBLS	5.73	149	3,540	44.25
33 SUWANNEE	1-3	153	1,142	1.0	96.13	4.3	14,621	LIGHT OIL	2,861 BBLS	5.80	16,597	377,853	33.09
34 TURNER	1-4	149	285	0.3	94.44	21.3	17,635	LIGHT OIL	867 BBLS	5.80	5,026	115,409	40.49
35 OTHER & START UP		-	100	-	0.00	0.0	373,594	LIGHT OIL	6,446 BBLS	5.80	37,359	826,563	826.56
36 TOTAL			3,311,455								29,345,705	145,250,812	4.39

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-13

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	131,194	47.0	90.62	50.1	10,908	COAL	57,968 TONS	24.69	1,431,054	6,723,530	5.12
3 CRYSTAL RIVER	2	494	175,572	47.8	94.39	49.0	10,782	COAL	76,678 TONS	24.69	1,892,960	8,844,968	5.04
4 CRYSTAL RIVER	4	722	410,292	76.4	93.50	79.1	10,609	COAL	188,612 TONS	23.08	4,352,628	14,803,169	3.61
5 CRYSTAL RIVER	5	700	390,277	74.9	71.45	77.7	10,781	COAL	182,324 TONS	23.08	4,207,522	14,329,988	3.67
6 ANCLOTE	1	501	0	0.0	3.02	31.4	0	HEAVY OIL	0 BBLS		0	0	0.00
7 ANCLOTE	2	510	3,401	11.8	93.63	26.9	12,284	HEAVY OIL	6,377 BBLS	6.55	41,779	503,374	14.80
8 SUWANNEE	1	30	0	0.0	95.81	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	28.03	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	95.48	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11 ANCLOTE	1	501	111,547	29.9	0.00	31.4	12,160	GAS	1,356,372 MCF	1.00	1,356,372	7,141,128	6.40
12 ANCLOTE	2	510	41,458	11.8	0.00	26.9	12,285	GAS	509,305 MCF	1.00	509,305	3,290,361	7.94
13 AVON PARK	1-2	49	576	1.7	76.87	53.8	16,269	GAS	9,371 MCF	1.00	9,371	62,102	10.78
14 BARTOW	1-4	177	4,076	3.2	96.85	25.1	14,071	GAS	57,355 MCF	1.00	57,355	379,240	7.83
15 BARTOW CC	1	1,159	722,793	83.8	94.47	88.3	7,249	GAS	5,239,550 MCF	1.00	5,239,550	28,304,274	3.92
16 DEBARY	1-10	645	16,748	3.9	95.81	11.2	13,182	GAS	220,766 MCF	1.00	220,766	1,198,614	7.16
17 HIGGINS	1-4	113	3,369	4.0	87.82	22.2	16,253	GAS	54,758 MCF	1.00	54,758	287,933	8.55
18 HINES CC	1-4	1,912	1,153,765	81.1	93.45	21.5	7,246	GAS	8,359,830 MCF	1.00	8,359,830	45,804,274	3.97
19 INT CITY	1-14	987	59,958	8.7	95.94	8.7	13,108	GAS	785,933 MCF	1.00	785,933	4,554,950	7.60
20 SUWANNEE	1	52	17,021	44.0	95.16	45.9	13,926	GAS	237,089 MCF	1.00	237,089	1,314,981	7.73
21 SUWANNEE	2	50	13,275	35.7	97.74	39.1	14,294	GAS	189,759 MCF	1.00	189,759	1,051,156	7.92
22 SUWANNEE	3	51	28,017	73.8	98.39	77.4	11,982	GAS	335,709 MCF	1.00	335,709	1,763,398	6.29
23 TIGER BAY CC	1	204	120,479	79.4	91.47	96.8	7,255	GAS	874,080 MCF	1.00	874,080	4,851,122	4.03
24 UNIV OF FLA. CC	1	46	32,616	95.3	97.42	97.8	9,428	GAS	307,506 MCF	1.00	307,506	1,592,934	4.88
25 AVON PARK	1-2	49	57	1.7	76.87	430.6	18,561	LIGHT OIL	183 BBLS	5.78	1,058	24,051	42.19
26 BARTOW	1-4	177	192	3.2	96.85	344.5	15,885	LIGHT OIL	526 BBLS	5.80	3,050	69,512	36.20
27 BAYBORO	1-4	174	1,649	1.3	94.68	17.9	14,876	LIGHT OIL	4,232 BBLS	5.80	24,531	575,976	34.93
28 DEBARY	1-10	645	1,928	3.9	95.81	46.7	14,568	LIGHT OIL	4,846 BBLS	5.80	28,087	645,205	33.46
29 HIGGINS	1-4	113	0	0.0	87.82	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31 INT CITY	1-14	987	4,030	8.7	95.94	49.5	15,265	LIGHT OIL	10,614 BBLS	5.80	61,517	1,405,631	34.88
32 RIO PINAR	1	12	38	0.4	97.42	75.0	18,611	LIGHT OIL	116 BBLS	5.78	670	15,147	42.08
33 SUWANNEE	1-3	153	993	0.9	97.10	4.0	14,693	LIGHT OIL	2,518 BBLS	5.79	14,590	331,281	33.36
34 TURNER	1-4	149	437	0.4	95.74	19.6	17,590	LIGHT OIL	1,327 BBLS	5.79	7,687	175,303	40.12
35 OTHER & START UP		-	105	-	0.00	0.0	267,758	LIGHT OIL	4,851 BBLS	5.80	28,115	624,115	594.40
36 TOTAL			3,445,881								30,632,611	150,807,717	4.37

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-13

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	117,770	43.6	31.22	47.7	10,951	COAL	52,369 TONS	24.63	1,289,751	5,991,319	5.09
3 CRYSTAL RIVER	2	494	155,454	43.7	90.39	46.8	10,807	COAL	68,214 TONS	24.63	1,679,987	7,756,407	4.99
4 CRYSTAL RIVER	4	722	386,835	74.4	92.06	78.9	10,614	COAL	177,850 TONS	23.09	4,105,895	14,105,508	3.65
5 CRYSTAL RIVER	5	700	367,543	72.9	49.57	76.8	10,795	COAL	171,665 TONS	23.09	3,967,721	13,651,334	3.71
6 ANCLOTE	1	501	0	0.0	2.86	30.4	0	HEAVY OIL	0 BBLS		0	0	0.00
7 ANCLOTE	2	510	1,957	5.3	94.83	27.2	12,329	HEAVY OIL	3,683 BBLS	6.55	24,128	290,704	14.85
8 SUWANNEE	1	30	0	0.0	93.00	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	94.33	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	26.67	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11 ANCLOTE	1	501	104,257	28.9	0.00	30.4	12,216	GAS	1,273,584 MCF	1.00	1,273,584	6,684,076	6.41
12 ANCLOTE	2	510	21,242	6.3	0.00	27.2	12,326	GAS	261,835 MCF	1.00	261,835	2,071,512	9.75
13 AVON PARK	1-2	49	152	0.4	83.50	45.8	16,513	GAS	2,510 MCF	1.00	2,510	30,950	20.36
14 BARTOW	1-4	177	2,089	1.6	73.00	22.8	14,279	GAS	29,829 MCF	1.00	29,829	155,497	7.44
15 BARTOW CC	1	1,159	706,707	84.7	85.96	87.9	7,228	GAS	5,107,848 MCF	1.00	5,107,848	26,163,382	3.99
16 DEBARY	1-10	645	11,236	2.5	95.30	10.0	13,261	GAS	149,005 MCF	1.00	149,005	874,361	7.78
17 HIGGINS	1-4	113	1,101	1.4	88.75	21.7	16,431	GAS	18,091 MCF	1.00	18,091	101,964	9.26
18 HINES CC	1-4	1,912	1,097,179	79.7	60.08	21.6	7,260	GAS	7,965,084 MCF	1.00	7,965,084	44,700,747	4.07
19 INT CITY	1-14	987	35,892	5.3	95.60	6.6	13,145	GAS	471,792 MCF	1.00	471,792	2,938,210	8.19
20 SUWANNEE	1	52	9,764	26.1	95.00	50.3	13,950	GAS	136,211 MCF	1.00	136,211	715,269	7.33
21 SUWANNEE	2	50	2,124	5.9	95.67	37.9	15,056	GAS	31,979 MCF	1.00	31,979	210,815	9.93
22 SUWANNEE	3	51	25,377	69.1	99.33	74.0	11,999	GAS	304,501 MCF	1.00	304,501	1,482,503	5.84
23 TIGER BAY CC	1	294	90,516	61.6	92.67	96.7	7,262	GAS	657,372 MCF	1.00	657,372	3,972,300	4.39
24 UNIV OF FLA. CC	1	46	21,276	64.2	65.17	97.8	9,430	GAS	200,625 MCF	1.00	200,625	1,109,718	5.22
25 AVON PARK	1-2	49	5	0.4	83.50	0.0	17,600	LIGHT OIL	15 BBLS	5.87	88	2,468	49.36
26 BARTOW	1-4	177	10	1.6	73.00	0.0	16,100	LIGHT OIL	28 BBLS	5.75	161	3,680	36.80
27 BAYBORO	1-4	174	405	0.3	95.58	17.9	15,067	LIGHT OIL	1,053 BBLS	5.79	6,102	156,351	38.61
28 DEBARY	1-10	645	241	2.5	95.30	177.9	15,589	LIGHT OIL	648 BBLS	5.80	3,757	102,304	42.45
29 HIGGINS	1-4	113	0	0.0	88.75	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31 INT CITY	1-14	987	1,656	5.3	95.60	70.4	15,367	LIGHT OIL	4,391 BBLS	5.80	25,448	607,863	36.71
32 RIO PINAR	1	12	0	0.0	98.00	0.0	0	LIGHT OIL	0 BBLS		0	235	0.00
33 SUWANNEE	1-3	153	437	0.4	96.67	2.4	14,822	LIGHT OIL	1,118 BBLS	5.79	6,477	147,481	33.75
34 TURNER	1-4	149	12	0.0	97.17	0.0	17,667	LIGHT OIL	37 BBLS	5.73	212	6,139	67.83
35 OTHER & START UP			61	-	0.00	0.0	698,516	LIGHT OIL	7,352 BBLS	5.80	42,609	946,803	1555.41
36 TOTAL			3,161,298								27,762,602	136,985,940	4.33

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-13

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	375	67,525	24.2	82.23	48.1	10,941	COAL	30,090 TONS	24.55	738,815	3,410,515	5.05
3 CRYSTAL RIVER	2	494	55,943	15.2	89.63	46.2	10,820	COAL	24,652 TONS	24.55	605,304	2,821,489	5.04
4 CRYSTAL RIVER	4	722	342,952	63.8	94.83	65.3	10,810	COAL	160,539 TONS	23.09	3,707,269	12,878,652	3.76
5 CRYSTAL RIVER	5	700	318,041	61.1	95.37	63.3	10,986	COAL	151,303 TONS	23.09	3,493,098	12,172,837	3.83
6 ANCLOTE	1	501	0	0.0	95.62	29.0	0	HEAVY OIL	0 BBLS		0	0	0.00
7 ANCLOTE	2	510	700	1.2	3.97	29.5	11,926	HEAVY OIL	1,274 BBLS	6.55	8,348	100,579	14.37
8 SUWANNEE	1	30	0	0.0	95.16	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	95.48	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10 SUWANNEE	3	71	0	0.0	94.19	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11 ANCLOTE	1	501	106,217	28.5	0.00	29.0	12,322	GAS	1,308,858 MCF	1.00	1,308,858	6,716,563	6.32
12 ANCLOTE	2	510	3,964	1.2	0.00	29.5	11,932	GAS	47,299 MCF	1.00	47,299	942,407	23.77
13 AVON PARK	1-2	49	209	0.6	80.00	39.3	17,565	GAS	3,671 MCF	1.00	3,671	32,934	15.76
14 BARTOW	1-4	177	1,843	1.4	73.06	22.5	14,400	GAS	26,539 MCF	1.00	26,539	197,600	7.47
15 BARTOW CC	1	1,159	740,182	85.8	20.03	87.5	7,256	GAS	5,372,427 MCF	1.00	5,372,427	29,751,866	4.02
16 DEBARY	1-10	645	7,643	1.7	95.97	10.4	13,296	GAS	101,623 MCF	1.00	101,623	545,787	7.14
17 HIGGINS	1-4	113	1,001	1.2	89.35	17.7	17,743	GAS	17,761 MCF	1.00	17,761	97,424	9.73
18 HINES CC	1-4	1,912	837,949	58.9	76.10	20.9	7,435	GAS	6,230,036 MCF	1.00	6,230,036	34,725,524	4.14
19 INT CITY	1-14	987	25,225	3.7	95.48	6.8	13,121	GAS	330,978 MCF	1.00	330,978	1,966,569	7.80
20 SUWANNEE	1	52	5,147	13.3	94.84	74.4	13,980	GAS	71,953 MCF	1.00	71,953	388,478	7.55
21 SUWANNEE	2	50	4,003	10.8	96.13	37.9	14,575	GAS	58,342 MCF	1.00	58,342	293,917	7.34
22 SUWANNEE	3	51	26,096	68.8	98.39	73.0	12,027	GAS	313,851 MCF	1.00	313,851	1,495,645	5.73
23 TIGER BAY CC	1	204	62,528	41.2	89.03	95.2	7,353	GAS	459,745 MCF	1.00	459,745	2,749,515	4.40
24 UNIV OF FLA. CC	1	46	28,836	84.3	89.21	97.8	9,434	GAS	272,031 MCF	1.00	272,031	1,567,717	5.44
25 AVON PARK	1-2	49	3	0.6	80.00	0.0	21,000	LIGHT OIL	11 BBLS	5.73	63	1,906	63.53
26 BARTOW	1-4	177	26	1.4	73.06	14.7	15,231	LIGHT OIL	68 BBLS	5.82	396	9,023	34.70
27 BAYBORO	1-4	174	176	0.1	95.97	14.4	15,278	LIGHT OIL	464 BBLS	5.80	2,689	78,161	44.41
28 DEBARY	1-10	645	574	1.7	95.97	57.9	16,225	LIGHT OIL	1,608 BBLS	5.79	9,313	226,049	39.38
29 HIGGINS	1-4	113	0	0.0	89.35	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31 INT CITY	1-14	987	1,662	3.7	95.48	56.6	15,007	LIGHT OIL	4,302 BBLS	5.80	24,941	661,912	39.22
32 RIO PINAR	1	12	4	0.0	98.39	0.0	18,500	LIGHT OIL	13 BBLS	5.69	74	1,882	47.05
33 SUWANNEE	1-3	153	327	0.3	96.45	1.8	14,755	LIGHT OIL	833 BBLS	5.79	4,825	109,532	33.50
34 TURNER	1-4	149	9	0.0	95.97	0.0	17,333	LIGHT OIL	27 BBLS	5.78	156	6,872	76.36
35 OTHER & START UP		-	22	-	0.00	0.0	1,447,699	LIGHT OIL	5,495 BBLS	5.80	31,849	707,053	3213.88
36 TOTAL			2,638,827								23,243,154	114,538,238	4.34

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-13

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	376	23,199	8.6	69.58	35.5	11,072	COAL	10,494 TONS	24.48	256,969	1,244,862	5.37
3 CRYSTAL RIVER	2	500	107,150	29.8	92.09	32.1	11,021	COAL	48,243 TONS	24.48	1,180,891	5,179,765	4.83
4 CRYSTAL RIVER	4	732	360,383	68.4	96.00	69.7	10,528	COAL	164,279 TONS	23.10	3,794,283	16,714,965	4.64
5 CRYSTAL RIVER	5	712	370,619	72.3	94.71	74.8	10,357	COAL	166,195 TONS	23.10	3,838,543	16,862,101	4.55
6 ANCLOTE	1	517	0	0.0	95.57	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
7 ANCLOTE	2	521	0	0.0	3.33	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	93.33	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	94.00	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10 SUWANNEE	3	73	0	0.0	94.33	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11 ANCLOTE	1	517	35,577	9.6	0.00	29.9	13,510	GAS	480,636 MCF	1.00	480,636	2,502,300	7.03
12 ANCLOTE	2	521	0	0.0	0.00	0.0	0	GAS	0 MCF		0	312,522	0.00
13 AVON PARK	1-2	69	7	0.0	77.83	0.0	15,143	GAS	106 MCF	1.00	106	16,813	237.33
14 BARTOW	1-4	228	66	0.0	72.75	809.9	13,424	GAS	886 MCF	1.00	886	19,662	29.79
15 BARTOW CC	1	1,279	678,204	73.6	99.02	79.2	7,211	GAS	4,890,621 MCF	1.00	4,890,621	28,360,231	4.18
16 DEBARY	1-10	785	341	0.1	96.30	526.5	12,745	GAS	4,346 MCF	1.00	4,346	35,426	10.39
17 HIGGINS	1-4	129	23	0.0	87.33	0.0	17,000	GAS	391 MCF	1.00	391	17,408	75.69
18 HINES CC	1-4	2,204	686,939	43.3	94.74	30.3	7,276	GAS	4,998,054 MCF	1.00	4,998,054	29,802,892	4.34
19 INT CITY	1-14	1,186	4,329	0.5	95.45	86.7	12,873	GAS	55,726 MCF	1.00	55,726	332,020	7.67
20 SUWANNEE	1	67	1,216	2.5	94.00	1817.9	12,864	GAS	15,693 MCF	1.00	15,693	84,519	6.94
21 SUWANNEE	2	66	334	0.7	97.00	28.1	14,805	GAS	4,945 MCF	1.00	4,945	27,738	8.30
22 SUWANNEE	3	67	23,214	48.1	97.67	51.0	11,691	GAS	271,405 MCF	1.00	271,405	1,249,543	5.38
23 TIGER BAY CC	1	225	34,623	21.5	89.09	92.7	7,470	GAS	260,133 MCF	1.00	260,133	1,653,950	4.75
24 UNIV OF FLA CC	1	47	33,869	100.1	98.00	102.1	9,427	GAS	319,275 MCF	1.00	319,275	1,767,139	5.22
25 AVON PARK	1-2	69	0	0.0	77.83	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
26 BARTOW	1-4	228	0	0.0	72.75	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
27 BAYBORO	1-4	231	0	0.0	95.67	0.0	0	LIGHT OIL	0 BBLS		0	16,888	0.00
28 DEBARY	1-10	785	4	0.1	96.30	0.0	19,000	LIGHT OIL	13 BBLS	5.85	76	19,889	497.23
29 HIGGINS	1-4	129	0	0.0	87.33	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31 INT CITY	1-14	1,186	15	0.5	95.45	0.0	15,000	LIGHT OIL	38 BBLS	5.92	225	54,251	361.67
32 RIO PINAR	1	16	0	0.0	98.00	0.0	0	LIGHT OIL	0 BBLS		0	235	0.00
33 SUWANNEE	1-3	200	2	0.0	96.22	0.0	15,000	LIGHT OIL	5 BBLS	6.00	30	681	34.05
34 TURNER	1-4	199	0	0.0	96.83	0.0	0	LIGHT OIL	0 BBLS		0	3,384	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	6,189 BBLS	5.80	35,872	796,224	0.00
36 TOTAL			2,360,316								20,409,006	107,075,205	4.54

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-13

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2 CRYSTAL RIVER	1	376	3,031	1.1	91.18	42.4	10,908	COAL	1,352 TONS	24.45	33,062	269,902	9.56
3 CRYSTAL RIVER	2	500	118,277	31.8	90.60	34.0	10,939	COAL	52,924 TONS	24.45	1,293,826	5,586,766	4.72
4 CRYSTAL RIVER	4	732	441,433	81.1	93.79	84.6	10,377	COAL	198,302 TONS	23.10	4,580,902	15,891,041	3.60
5 CRYSTAL RIVER	5	712	443,162	83.7	92.47	88.5	10,229	COAL	196,240 TONS	23.10	4,533,181	15,732,177	3.55
6 ANCLOTE	1	517	0	0.0	91.12	18.0	0	HEAVY OIL	0 BBLS		0	0	0.00
7 ANCLOTE	2	521	0	0.0	93.36	25.4	0	HEAVY OIL	0 BBLS		0	0	0.00
8 SUWANNEE	1	30	0	0.0	93.23	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9 SUWANNEE	2	30	0	0.0	96.13	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10 SUWANNEE	3	73	0	0.0	95.48	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11 ANCLOTE	1	517	65,411	17.0	0.00	18.0	13,800	GAS	902,648 MCF	1.00	902,648	4,768,963	7.29
12 ANCLOTE	2	521	3,972	1.0	0.00	25.4	12,258	GAS	48,687 MCF	1.00	48,687	811,708	20.44
13 AVON PARK	1-2	69	0	0.0	81.29	0.0	0	GAS	0 MCF		0	16,133	0.00
14 BARTOW	1-4	228	0	0.0	72.58	0.0	0	GAS	0 MCF		0	15,630	0.00
15 BARTOW CC	1	1279	682,218	71.7	95.48	74.6	7,213	GAS	4,920,950 MCF	1.00	4,920,950	28,977,185	4.25
16 DEBARY	1-10	785	72	0.0	95.94	9.2	12,597	GAS	907 MCF	1.00	907	19,833	27.55
17 HIGGINS	1-4	129	0	0.0	89.03	0.0	0	GAS	0 MCF		0	15,628	0.00
18 HINES CC	1-4	2,204	742,944	45.3	95.27	19.8	7,229	GAS	5,370,752 MCF	1.00	5,370,752	32,233,753	4.34
19 INT CITY	1-14	1,186	964	0.1	88.38	6.8	12,703	GAS	12,246 MCF	1.00	12,246	110,673	11.48
20 SUWANNEE	1	97	390	0.8	95.16	582.1	13,177	GAS	5,139 MCF	1.00	5,139	36,839	9.45
21 SUWANNEE	2	96	97	0.2	96.06	29.4	14,062	GAS	1,364 MCF	1.00	1,364	11,530	11.89
22 SUWANNEE	3	97	23,686	47.5	96.71	49.8	11,635	GAS	275,585 MCF	1.00	275,585	1,290,065	5.45
23 TIGER BAY CC	1	225	5,695	3.5	88.33	93.6	7,573	GAS	44,642 MCF	1.00	44,642	363,162	6.16
24 UNIV OF FLA. CC	1	47	34,790	99.5	97.42	102.1	9,427	GAS	327,959 MCF	1.00	327,959	1,847,974	5.31
25 AVON PARK	1-2	69	0	0.0	81.29	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
26 BARTOW	1-4	228	0	0.0	72.58	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
27 BAYBORO	1-4	231	0	0.0	95.24	0.0	0	LIGHT OIL	0 BBLS		0	16,888	0.00
28 DEBARY	1-10	785	0	0.0	95.94	0.0	0	LIGHT OIL	0 BBLS		0	18,193	0.00
29 HIGGINS	1-4	129	0	0.0	89.03	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31 INT CITY	1-14	1,186	0	0.0	88.38	0.0	0	LIGHT OIL	0 BBLS		0	42,228	0.00
32 RIO PINAR	1	16	0	0.0	99.03	0.0	0	LIGHT OIL	0 BBLS		0	235	0.00
33 SUWANNEE	1-3	200	2	0.0	97.31	0.1	15,000	LIGHT OIL	5 BBLS	6.00	30	664	34.20
34 TURNER	1-4	199	0	0.0	93.75	0.0	0	LIGHT OIL	0 BBLS		0	3,384	0.00
35 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	6,371 BBLS	5.80	36,924	823,013	0.00
36 TOTAL			2,566,344								22,388,704	108,923,807	4.24

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2013

			Act Jan-13	Act Feb-13	Act Mar-13	Act Apr-13	Act May-13	Act Jun-13	Subtotal
	HEAVY OIL								
1	PURCHASES:								
2	UNITS	BBL	(56,809)	(254,694)	818	733	(10,020)	0	(319,972)
3	UNIT COST	$/BBL	97.14	81.68	706.03	1891.39	(245.76)	0.00	68.43
4	AMOUNT	$	(5,518,447)	(20,802,659)	577,533	1,386,387	2,462,534	0	(21,894,652)
5	BURNED:								
6	UNITS	BBL	12,586	7,205	53,780	74,020	32,433	627	180,653
7	UNIT COST	$/BBL	78.97	75.09	75.08	75.14	75.15	87.38	75.43
8	AMOUNT	$	994,063	541,010	4,037,714	5,562,175	2,437,288	54,784	13,627,034
9	ENDING INVENTORY:								
10	UNITS	BBL	515,404	253,505	200,544	133,346	105,559	104,932	
11	UNIT COST	$/BBL	68.69	55.45	52.85	50.28	74.21	74.13	
12	AMOUNT	$	35,401,779	14,058,109	10,597,911	6,704,784	7,833,173	7,778,389	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	0	1	0	0	20,000	0	20,001
15	UNIT COST	$/BBL	0.00	142,369.66	0.00	0.00	134.40	0.00	203.69
16	AMOUNT	$	698,999	142,370	170,538	185,095	2,688,040	192,943	4,077,985
17	BURNED:								
18	UNITS	BBL	9,306	15,500	8,402	11,026	13,004	17,314	74,552
19	UNIT COST	$/BBL	125.54	106.09	128.24	122.64	122.97	115.70	118.64
20	AMOUNT	$	1,168,288	1,644,322	1,077,464	1,352,253	1,599,091	2,003,180	8,844,597
21	ENDING INVENTORY:								
22	UNITS	BBL	1,107,628	1,092,128	1,083,725	1,072,693	1,080,005	1,062,688	
23	UNIT COST	$/BBL	110.86	111.06	111.08	111.13	111.43	111.54	
24	AMOUNT	$	122,790,925	121,288,720	120,381,452	119,213,526	120,342,801	118,532,153	
	COAL								
25	PURCHASES:								
26	UNITS	TON	350,415	349,656	306,625	356,384	371,512	412,043	2,146,635
27	UNIT COST	$/TON	88.22	90.33	81.83	91.30	91.68	92.93	89.67
28	AMOUNT	$	30,913,320	31,585,965	25,092,224	32,537,003	34,059,133	38,291,865	192,479,510
29	BURNED:								
30	UNITS	TON	325,923	331,764	330,724	491,918	483,335	448,177	2,411,841
31	UNIT COST	$/TON	86.33	85.34	91.54	85.69	90.31	93.40	88.89
32	AMOUNT	$	28,138,148	28,312,028	30,273,745	42,151,769	43,648,466	41,861,777	214,385,933
33	ENDING INVENTORY:								
34	UNITS	TON	1,244,156	1,262,048	1,237,948	1,102,415	990,592	954,458	
35	UNIT COST	$/TON	92.61	93.89	91.53	94.07	95.00	94.86	
36	AMOUNT	$	115,222,812	118,496,749	113,315,228	103,700,461	94,111,129	90,541,216	
	GAS								
37	BURNED:								
38	UNITS	MCF	12,758,401	11,475,634	13,246,727	11,359,331	13,586,022	16,641,086	79,067,201
39	UNIT COST	$/MCF	5.91	5.80	5.66	6.06	5.78	6.22	5.92
40	AMOUNT	$	75,443,087	66,615,453	74,958,388	68,823,910	78,547,559	103,451,635	467,840,033
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2013

			Est Jul-13	Est Aug-13	Est Sep-13	Est Oct-13	Est Nov-13	Est Dec-13	Total
	HEAVY OIL								
1	PURCHASES:								
2	UNITS	BBL	6,157	6,377	3,683	1,274	0	0	(302,481)
3	UNIT COST	$/BBL	78.95	78.94	78.93	78.95	0.00	0.00	67.82
4	AMOUNT	$	486,077	503,374	290,704	100,579	0	0	(20,513,918)
5	BURNED:								
6	UNITS	BBL	6,157	6,377	3,683	1,274	0	0	198,144
7	UNIT COST	$/BBL	78.95	78.94	78.93	78.95	0.00	0.00	75.74
8	AMOUNT	$	486,077	503,374	290,704	100,579	0	0	15,007,768
9	ENDING INVENTORY:								
10	UNITS	BBL	104,932	104,932	104,932	104,932	0	0	
11	UNIT COST	$/BBL	78.95	78.94	78.93	78.95	0.00	0.00	
12	AMOUNT	$	8,284,077	8,282,902	8,282,419	8,284,109	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	31,875	29,213	14,642	12,821	6,245	6,376	121,172
15	UNIT COST	$/BBL	131.63	132.35	135.04	135.91	142.76	141.88	145.71
16	AMOUNT	$	4,195,789	3,866,221	1,977,324	1,742,390	891,552	904,625	17,655,887
17	BURNED:								
18	UNITS	BBL	31,875	29,213	14,642	12,821	6,245	6,376	175,723
19	UNIT COST	$/BBL	131.63	132.35	135.04	135.91	142.76	141.88	127.60
20	AMOUNT	$	4,195,789	3,866,221	1,977,324	1,742,390	891,552	904,625	22,422,499
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	131.63	132.35	135.04	135.91	142.76	141.88	
24	AMOUNT	$	139,881,621	140,646,757	143,505,388	144,429,926	151,709,339	150,774,173	
	COAL								
25	PURCHASES:								
26	UNITS	TON	509,105	505,582	470,298	366,584	389,211	448,818	4,836,233
27	UNIT COST	$/TON	89.29	88.42	88.26	85.34	102.78	83.55	89.52
28	AMOUNT	$	45,455,587	44,701,655	41,506,568	31,283,493	40,001,693	37,499,886	432,928,392
29	BURNED:								
30	UNITS	TON	509,105	505,582	470,298	366,584	389,211	448,818	5,101,439
31	UNIT COST	$/TON	89.29	88.42	88.26	85.34	102.78	83.55	89.16
32	AMOUNT	$	45,455,587	44,701,655	41,506,568	31,283,493	40,001,693	37,499,886	454,834,815
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	89.29	88.42	88.26	85.34	102.78	83.55	
36	AMOUNT	$	85,219,069	84,389,549	84,236,550	81,451,441	98,095,757	79,747,352	
	GAS								
37	BURNED:								
38	UNITS	MCF	17,129,241	18,537,363	16,610,266	14,615,114	11,302,217	11,910,879	169,172,281
39	UNIT COST	$/MCF	5.55	5.48	5.61	5.57	5.86	5.92	5.77
40	AMOUNT	$	95,113,359	101,536,467	93,211,344	81,411,776	66,181,963	70,519,096	975,814,038
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jan-13	ECONSALE	--	1,926		1,926	3.223	3.837	62,075	73,910	11,835
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	102,770		102,770	2.894	2.894	2,974,066	2,974,066	0
	TOTAL		104,696		104,696	2.900	2.911	3,036,141	3,047,976	11,835
Feb-13	ECONSALE	--	5,174		5,174	2.821	3.409	145,944	176,373	30,429
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	52,531		52,531	4.092	4.092	2,149,805	2,149,805	0
	TOTAL		57,705		57,705	3.978	4.031	2,295,748	2,326,177	30,429
Mar-13	ECONSALE	--	8,636		8,636	3.127	3.686	270,085	318,324	48,239
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	64,442		64,442	3.470	3.470	2,236,257	2,236,257	0
	TOTAL		73,078		73,078	3.430	3.496	2,506,342	2,554,581	48,239
Apr-13	ECONSALE	--	11,559		11,559	2.780	3.551	321,291	410,419	89,128
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	77,205		77,205	3.403	3.403	2,627,437	2,627,437	0
	TOTAL		88,764		88,764	3.322	3.422	2,948,728	3,037,856	89,128
May-13	ECONSALE	--	2,468		2,468	3.277	3.880	80,866	95,748	14,863
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	122,336		122,336	4.018	4.018	4,915,305	4,915,305	0
	TOTAL		124,804		124,804	4.003	4.015	4,996,191	5,011,053	14,863
Jun-13	ECONSALE	--	5,633		5,633	3.637	4.934	204,859	277,946	73,087
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	101,626		101,626	3.942	3.942	4,005,767	4,005,767	0
	TOTAL		107,259		107,259	3.926	3.994	4,210,626	4,283,713	73,087
Jan	ECONSALE	--	35,396		35,396	3.066	3.822	1,085,140	1,352,720	267,580
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-13	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	520,910		520,910	3.630	3.630	18,908,637	18,908,637	0
	TOTAL		556,306		556,306	3.594	3.642	19,993,777	20,261,357	267,580

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-13	ECONSALE	--	11,977		11,977	4.048	4.898	484,794	586,601	101,807
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	129,920		129,920	3.835	3.835	4,982,859	4,982,859	0
	TOTAL		141,897		141,897	3.853	3.925	5,467,653	5,569,460	101,807
Aug-13	ECONSALE	--	6,130		6,130	4.791	5.797	293,697	355,373	61,676
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	136,437		136,437	3.791	3.791	5,171,717	5,171,717	0
	TOTAL		142,567		142,567	3.834	3.877	5,465,414	5,527,090	61,676
Sep-13	ECONSALE	--	1,395		1,395	4.003	4.844	55,842	67,569	11,727
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	137,921		137,921	3.856	3.856	5,318,559	5,318,559	0
	TOTAL		139,316		139,316	3.858	3.866	5,374,401	5,386,128	11,727
Oct-13	ECONSALE	--	7,138		7,138	3.385	4.095	241,586	292,319	50,733
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	120,818		120,818	3.872	3.872	4,677,594	4,677,594	0
	TOTAL		127,956		127,956	3.844	3.884	4,919,180	4,969,913	50,733
Nov-13	ECONSALE	--	1,584		1,584	2.933	3.548	46,452	56,208	9,756
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	79,440		79,440	4.028	4.028	3,199,458	3,199,458	0
	TOTAL		81,024		81,024	4.006	4.018	3,245,910	3,255,666	9,756
Dec-13	ECONSALE	--	969		969	3.241	3.922	31,410	38,006	6,596
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	57,502		57,502	4.065	4.065	2,337,284	2,337,284	0
	TOTAL		58,471		58,471	4.051	4.062	2,368,694	2,375,290	6,596
Jan-13	ECONSALE	--	64,589		64,589	3.466	4.256	2,238,921	2,748,796	509,875
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-13	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,182,948		1,182,948	3.770	3.770	44,596,108	44,596,108	0
	TOTAL		1,247,537		1,247,537	3.754	3.795	46,835,030	47,344,904	509,875

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							C/KWH		
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-13	OTHER	--	0			0	0.000	0.000	0
Act	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	17,997			17,997	7.437	7.437	1,338,431
	SOCO Franklin	--	94,651			94,651	3.807	3.807	3,603,677
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (Reliant)	--	0			0	0.000	0.000	51,114
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		112,648	0	0	112,648	4.433	4.433	4,993,222
Feb-13	OTHER	--	0			0	0.000	0.000	0
Act	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	26,280			26,280	6.683	6.683	1,756,366
	SOCO Franklin	--	155,629			155,629	3.423	3.423	5,326,759
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (Reliant)	--	2,865			2,865	11.088	11.088	317,663
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		184,774	0	0	184,774	4.005	4.005	7,400,788
Mar-13	OTHER	--	0			0	0.000	0.000	0
Act	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	25,396			25,396	7.324	7.324	1,860,121
	SOCO Franklin	--	158,663			158,663	3.714	3.714	5,900,489
	SOCO Scherer	--	0			0	0.000	0.000	(169,642)
	Vandolah (Reliant)	--	3,738			3,738	12.725	12.725	475,647
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		187,997	0	0	187,997	4.291	4.291	8,066,615
Apr-13	OTHER	--	0			0	0.000	0.000	0
Act	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	83,949			83,949	6.773	6.773	5,685,688
	SOCO Franklin	--	59,400			59,400	4.377	4.377	2,599,860
	SOCO Scherer	--	26,592			26,592	3.035	3.035	807,096
	Vandolah (Reliant)	--	29,260			29,260	7.689	7.689	2,249,728
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		199,201	0	0	199,201	5.694	5.694	11,342,391
May-13	OTHER	--	0			0	0.000	0.000	0
Act	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	85,369			85,369	6.884	6.884	5,876,830
	SOCO Franklin	--	11,820			11,820	7.379	7.379	872,177
	SOCO Scherer	--	45,240			45,240	3.052	3.052	1,380,937
	Vandolah (Reliant)	--	27,750			27,750	7.754	7.754	2,151,622
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		170,179	0	0	170,179	6.042	6.042	10,281,566
Jun-13	OTHER	--	0			0	0.000	0.000	0
Act	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	89,915			89,915	7.492	7.492	6,736,302
	SOCO Franklin	--	150,049			150,049	3.933	3.933	5,901,142
	SOCO Scherer	--	36,008			36,008	3.313	3.313	1,193,059
	Vandolah (Reliant)	--	66,828			66,828	8.094	8.094	5,409,195
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		342,800	0	0	342,800	5.613	5.613	19,239,698
Jan-13	OTHER	--	0			0	0.000	0.000	0
THRU	TECO	--	0			0	0.000	0.000	0
Jun-13	SHADY HILLS	--	328,906			328,906	7.070	7.070	23,253,738
	SOCO Franklin	--	630,412			630,412	3.839	3.839	24,204,124
	SOCO Scherer	--	107,840			107,840	2.978	2.978	3,211,450
	Vandolah (Reliant)	--	130,441			130,441	8.168	8.168	10,654,969
	Vandolah (NSG)	--	0			0	0.000	0.000	0
	TOTAL		1,197,599	0	0	1,197,599	5.121	5.121	61,324,281

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-13	OTHER	--	0			0	0.000	0.000	0
Est	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	96,138			96,138	7.230	7.230	6,951,195
	SOCO Franklin	--	183,150			183,150	4.321	4.321	7,914,166
	SOCO Scherer	--	37,022			37,022	3.552	3.552	1,315,077
	Vandolah (Reliant)	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	93,341			93,341	8.332	8.332	7,777,154
	TOTAL		409,651	0	0	409,651	5.848	5.848	23,957,592
Aug-13	OTHER	--	0			0	0.000	0.000	0
Est	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	97,047			97,047	7.166	7.166	6,954,523
	SOCO Franklin	--	210,904			210,904	4.202	4.202	8,861,968
	SOCO Scherer	--	37,398			37,398	3.547	3.547	1,326,472
	Vandolah (Reliant)	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	98,229			98,229	8.095	8.095	7,952,027
	TOTAL		443,578	0	0	443,578	5.657	5.657	25,094,990
Sep-13	OTHER	--	0			0	0.000	0.000	0
Est	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	76,678			76,678	7.655	7.655	5,869,816
	SOCO Franklin	--	192,471			192,471	4.273	4.273	8,223,718
	SOCO Scherer	--	36,065			36,065	3.566	3.566	1,286,076
	Vandolah (Reliant)	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	72,564			72,564	8.724	8.724	6,330,465
	TOTAL		377,778	0	0	377,778	5.747	5.747	21,710,075
Oct-13	OTHER	--	0			0	0.000	0.000	0
Est	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	60,461			60,461	7.750	7.750	4,685,441
	SOCO Franklin	--	164,928			164,928	4.386	4.386	7,233,758
	SOCO Scherer	--	43,937			43,937	3.472	3.472	1,525,409
	Vandolah (Reliant)	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	59,291			59,291	8.620	8.620	5,110,664
	TOTAL		328,617	0	0	328,617	5.646	5.646	18,555,272
Nov-13	OTHER	--	0			0	0.000	0.000	0
Est	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	17,443			17,443	10.641	10.641	1,856,065
	SOCO Franklin	--	78,687			78,687	5.749	5.749	4,523,363
	SOCO Scherer	--	31,023			31,023	3.651	3.651	1,132,509
	Vandolah (Reliant)	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	20,195			20,195	10.117	10.117	2,043,050
	TOTAL		147,348	0	0	147,348	6.485	6.485	9,554,987
Dec-13	OTHER	--	0			0	0.000	0.000	0
Est	TECO	--	0			0	0.000	0.000	0
	SHADY HILLS	--	4,207			4,207	11.740	11.740	493,882
	SOCO Franklin	--	64,483			64,483	6.210	6.210	4,004,696
	SOCO Scherer	--	34,389			34,389	3.598	3.598	1,237,229
	Vandolah (Reliant)	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	6,427			6,427	11.875	11.875	763,209
	TOTAL		109,506	0	0	109,506	5.935	5.935	6,499,016
Jan-13	OTHER	--	0			0	0.000	0.000	0
THRU	TECO	--	0			0	0.000	0.000	0
Dec-13	SHADY HILLS	--	680,880			680,880	7.353	7.353	50,064,660
	SOCO Franklin	--	1,525,035			1,525,035	4.260	4.260	64,965,793
	SOCO Scherer	--	327,674			327,674	3.367	3.367	11,034,222
	Vandolah (Reliant)	--	130,441			130,441	8.168	8.168	10,654,969
	Vandolah (NSG)	--	350,047			350,047	8.564	8.564	29,976,569
TOTAL			3,014,077	0	0	3,014,077	5.531	5.531	166,696,213

Docket No. 130001-EI
Exhibit TGF-2, Part 1
Schedule E8

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) ENERGY COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(A)
Jan-13 Act	QUAL. FACILITIES	COGEN	398,306			398,306	4.958	11.857	19,749,624
Feb-13 Act	QUAL. FACILITIES	COGEN	348,660			348,660	4.716	12.577	16,442,524
Mar-13 Act	QUAL. FACILITIES	COGEN	387,335			387,335	4.669	11.739	18,086,280
Apr-13 Act	QUAL. FACILITIES	COGEN	323,617			323,617	5.008	13.475	16,205,598
May-13 Act	QUAL. FACILITIES	COGEN	379,863			379,863	4.826	12.042	18,334,050
Jun-13 Act	QUAL. FACILITIES	COGEN	375,483			375,483	5.246	12.544	19,697,765
Jul-13 Est	QUAL. FACILITIES	COGEN	370,526			370,526	4.859	12.256	18,004,359
Aug-13 Est	QUAL. FACILITIES	COGEN	288,665			288,665	4.534	12.735	13,089,077
Sep-13 Est	QUAL. FACILITIES	COGEN	279,363			279,363	4.526	13.000	12,644,871
Oct-13 Est	QUAL. FACILITIES	COGEN	257,426			257,426	4.624	13.820	11,903,930
Nov-13 Est	QUAL. FACILITIES	COGEN	273,210			273,210	4.633	13.297	12,657,284
Dec-13 Est	QUAL. FACILITIES	COGEN	351,982			351,982	4.478	10.805	15,760,883
TOTAL	QUAL. FACILITIES	COGEN	4,034,436			4,034,436	4.773	12.429	192,576,244

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-13	ECONPURCH	--	2,680	8.819	8.819	236,354	4.510	120,879	(115,475)
Act	SEPA	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		2,680	8.819	8.819	236,354	4.510	120,879	(115,475)
Feb-13	ECONPURCH	--	50	282.376	282.376	141,188	3.117	1,559	(139,629)
Act	SEPA	--	366	4.440	4.440	16,241	4.440	16,241	(0)
	TOTAL		416	37.862	37.862	157,429	4.281	17,800	(139,630)
Mar-13	ECONPURCH	--	9,285	5.823	5.823	540,628	5.281	490,311	(50,317)
Act	SEPA	--	957	4.469	4.469	42,775	4.469	42,775	(0)
	TOTAL		10,242	5.696	5.696	583,403	5.205	533,086	(50,317)
Apr-13	ECONPURCH	--	16,886	5.564	5.564	939,607	6.112	1,032,087	92,481
Act	SEPA	--	81	4.609	4.609	3,726	4.609	3,726	0
	TOTAL		16,967	5.560	5.560	943,332	6.105	1,035,813	92,481
May-13	ECONPURCH	--	40,140	5.228	5.228	2,098,620	5.541	2,224,082	125,462
Act	SEPA	--	4,278	4.511	4.511	192,965	4.511	192,965	0
	TOTAL		44,418	5.159	5.159	2,291,585	5.442	2,417,047	125,462
Jun-13	ECONPURCH	--	56,527	5.027	5.027	2,841,599	5.736	3,242,447	400,848
Act	SEPA	--	9,495	4.631	4.631	439,719	4.631	439,719	(0)
	TOTAL		66,022	4.970	4.970	3,281,318	5.577	3,682,166	400,848
Jan-13	ECONPURCH	--	125,568	5.414	5.414	6,797,996	5.66	7,111,366	313,370
THRU	SEPA	--	15,177	4.582	4.582	695,426	4.58	695,426	(0)
Jun-13									
	TOTAL		140,745	5.324	5.324	7,493,422	5.547	7,806,792	313,370

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-13	ECONPURCH	--	21,937	7.463	7.463	1,637,160	10.224	2,242,910	605,750
Est	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		25,164	6.978	6.978	1,756,060	9.386	2,361,810	605,750
Aug-13	ECONPURCH	--	19,437	8.523	8.523	1,656,547	11.676	2,269,470	612,923
Est	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		22,664	7.834	7.834	1,775,447	10.538	2,388,370	612,923
Sep-13	ECONPURCH	--	28,252	5.881	5.881	1,661,604	8.057	2,276,398	614,794
Est	SEPA	--	3,123	3.684	3.684	115,065	3.684	115,065	0
	TOTAL		31,375	5.663	5.663	1,776,669	7.622	2,391,463	614,794
Oct-13	ECONPURCH	--	25,667	6.326	6.326	1,623,673	8.667	2,224,432	600,759
Est	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		28,894	6.031	6.031	1,742,573	8.110	2,343,332	600,759
Nov-13	ECONPURCH	--	12,664	6.323	6.323	800,726	8.662	1,096,995	296,269
Est	SEPA	--	3,123	3.684	3.684	115,065	3.684	115,065	0
	TOTAL		15,787	5.801	5.801	915,791	7.678	1,212,060	296,269
Dec-13	ECONPURCH	--	7,595	7.737	7.737	587,636	10.600	805,062	217,426
Est	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		10,822	6.529	6.529	706,536	8.538	923,962	217,426
Jan-13	ECONPURCH	--	241,120	6.124	6.124	14,765,342	7.476	18,026,633	3,261,291
THRU	SEPA	--	34,331	4.081	4.081	1,401,156	4.081	1,401,156	(0)
Dec-13									
	TOTAL		275,451	5.869	5.869	16,166,498	7.053	19,427,789	3,261,291

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : January through June 2013

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 3,384,964	45.48%	10.50%	4.78%
Preferred Stock	23,017	0.31%	4.51%	0.01%
Long Term Debt	3,010,543	40.45%	5.73%	2.32%
Short Term Debt	20,229	0.27%	0.65%	0.00%
Customer Deposits - Active	168,807	2.27%	6.27%	0.14%
Customer Deposits - Inactive	882	0.01%	0.00%	0.00%
Deferred Tax	976,720	13.12%	0.00%	0.00%
Deferred Tax (FAS 109)	(145,373)	-1.95%	0.00%	0.00%
ITC	2,887	0.04%	8.36%	0.00%
	7,442,678	100.00%		7.25%

Total Debt	2.46%
Total Equity	4.79%

* May 2012 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2013 Actual/Estimated True-up Filing does not currently include a capital return component

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : July through December 2013

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 3,951,603	47.50%	10.50%	4.99%
Preferred Stock	17,874	0.21%	4.49%	0.01%
Long Term Debt	3,223,164	38.75%	5.61%	2.17%
Short Term Debt	35,074	0.42%	1.22%	0.01%
Customer Deposits - Active	182,636	2.20%	3.21%	0.07%
Customer Deposits - Inactive	1,162	0.01%	0.00%	0.00%
Deferred Tax	1,059,780	12.74%	0.00%	0.00%
Deferred Tax (FAS 109)	(155,042)	-1.86%	0.00%	0.00%
ITC	2,091	0.03%	8.22%	0.00%
	8,318,342	100.00%		7.25%

Total Debt	2.25%
Total Equity	5.00%

* May 2013 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2013 Actual/Estimated True-up Filing does not currently include a capital return component

Docket 130001-EI
Exhibit No. ____(TGF-2)
Part 2

PROGRESS ENERGY FLORIDA

CAPACITY COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2013

Schedule E12-A – Purchased Power Capacity Cost (Projected)

Schedule E12-B – Purchased Power Capacity Cost (Re-Projected)

Schedule E12-C – Variance Analysis (Re-projected vs. Projected)

Duke Energy Florida
Calculation of Projected Capacity Costs
For the Year 2013 - As re-filed on 10/2/12 in Docket 120001-EI

Docket No. 130001-EI
Exhibit__TGF-2, Part 2
Schedule E12-A
Page 1 of 1

		EST Jan-13	EST Feb-13	EST Mar-13	EST Apr-13	EST May-13	EST Jun-13	EST Jul-13	EST Aug-13	EST Sep-13	EST Oct-13	EST Nov-13	EST Dec-13	TOTAL
1	Base Production Level Capacity Costs													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	824,670	9,896,040
3	Auburndale Power Partners, L.P. (AUBSET)	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	43,335,108
4	Lake County (LAKCOUNT)	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	9,277,920
5	Lake Cogen Limited (LAKORDER)	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	-	-	-	-	-	26,150,313
6	Metro-Dade County (METRDADE)	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	417,869	15,642,419
7	Orange Cogen (ORANGECO)	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	35,490,060
8	Orlando Cogen Limited (ORLACOGL)	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	34,552,956
9	Pasco County Resource Recovery (PASCOUNT)	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	16,736,640
10	Pinellas County Resource Recovery (PINCOUNT)	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	39,840,480
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	68,504,532
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,352
13	Southern Scherer	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	18,343,440
14	Subtotal - Base Level Capacity Costs	28,937,033	28,937,033	28,937,033	28,937,033	28,937,033	28,937,033	28,937,033	25,201,274	25,201,274	25,201,274	25,201,274	24,216,933	327,581,260
15	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
16	Base Level Jurisdictional Capacity Costs	26,878,163	26,878,162	26,878,162	26,878,162	26,878,162	26,878,163	26,878,163	23,408,203	23,408,203	23,408,203	23,408,203	22,493,898	304,273,849
17	Intermediate Production Level Capacity Costs													
18	Southern Franklin	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	25,956,000
19	Schedule H Capacity Sales - NSB & RCID	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(10,942)	(131,304)
20	Subtotal - Intermediate Level Capacity Costs	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	2,152,058	25,824,696
21	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
22	Intermediate Level Jurisdictional Capacity Costs	1,564,611	1,564,611	1,564,611	1,564,611	1,564,612	1,564,611	1,564,611	1,564,611	1,564,611	1,564,611	1,564,611	1,564,611	18,775,330
23	Peaking Production Level Capacity Costs													
24	Chattahoochee	12,634	12,634	12,634	12,634	12,634	12,634	12,634	12,634	12,634	12,634	12,634	12,634	151,612
25	Shady Hills Power Company LLC	1,952,294	1,952,294	1,394,496	1,394,496	1,952,294	4,183,488	4,183,488	4,183,488	1,952,294	1,394,496	1,394,496	1,952,294	27,589,920
26	Vandolah (NSG)	2,660,851	2,676,173	1,898,784	1,876,896	2,584,243	5,400,884	5,384,448	5,340,872	2,520,403	1,838,592	1,882,368	2,676,173	36,740,487
27	Subtotal - Peaking Level Capacity Costs	4,625,780	4,641,102	3,305,914	3,284,026	4,549,172	9,596,986	9,580,570	9,536,794	4,485,332	3,245,722	3,289,498	4,641,102	64,782,000
28	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
29	Peaking Level Jurisdictional Capacity Costs	4,437,233	4,451,930	3,171,165	3,150,169	4,363,748	9,205,813	9,190,066	9,148,075	4,302,510	3,113,427	3,155,418	4,451,930	62,141,485
30	Other Capacity Costs													
31	Retail Wheeling	(50,606)	(9,946)	(423)	(216)	(8,176)	(339)	(13,256)	(28,542)	(710)	(7,754)	(559)	-	(118,528)
32	Other Jurisdictional Capacity Costs	(50,606)	(9,946)	(423)	(216)	(8,176)	(339)	(13,256)	(28,542)	(710)	(7,754)	(559)	-	(118,528)
33	**Total Capacity Costs (line 16+22+29+32)**	32,829,401	32,884,757	31,613,515	31,592,726	32,796,346	37,648,246	37,619,584	34,094,346	29,274,613	28,078,487	28,127,673	28,510,439	385,072,136
34	Estimated/Actual True-Up Provision - Jan - Dec 2012													10,485,622
35	**Total Capacity Costs w/ True-Up**													395,557,758
36	Revenue Tax Multiplier													1.00072
37	***Total Recoverable Capacity Costs***													395,842,560
38	**Nuclear Cost Recovery Clause**													142,730,579
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													142,833,345
41	**Total Recoverable Capacity & Nuclear Costs (line 37+40)**													538,675,905

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2013

Docket No. 130001-EI
Exhibit__TGF-2, Part 2
Schedule E12-B
Page 1 of 2

		ACT Jan-13	ACT Feb-13	ACT Mar-13	ACT Apr-13	ACT May-13	ACT Jun-13	EST Jul-13	EST Aug-13	EST Sep-13	EST Oct-13	EST Nov-13	EST Dec-13	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$9,896,040
3	Auburndale Power Partners, L.P. (AUBSET)	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	43,335,107
4	Lake County (LAKCOUNT)	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	9,277,920
5	Lake Cogen Limited (LAKORDER)	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	-	-	-	-	-	26,150,313
6	Metro-Dade County (METRDADE)	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	-	15,424,530
7	Orange Cogen (ORANGECO)	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	35,490,064
8	Orlando Cogen Limited (ORLACOGL)	2,951,657	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	34,625,199
9	Pasco County Resource Recovery (PASCOUNT)	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	16,736,640
10	Pinellas County Resource Recovery (PINCOUNT)	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	39,840,480
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	68,504,529
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	797,586	800,946	777,222	794,026	799,869	794,685	800,946	800,946	800,946	800,946	800,946	800,946	9,570,012
13	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Southern - Scherer	1,716,577	1,716,976	1,717,736	1,740,639	2,398,635	1,590,329	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	20,061,811
15	*Subtotal - Base Level Capacity Costs*	29,193,876	29,125,389	29,102,424	29,142,132	29,806,171	29,001,491	28,937,033	25,201,274	25,201,274	25,201,274	25,201,274	23,799,044	328,912,645
16	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
17	Base Level Junsdictional Capacity Costs	27,116,731	27,053,117	27,031,787	27,068,669	27,685,462	26,938,026	26,878,163	23,408,203	23,408,203	23,408,203	23,408,203	22,105,742	305,510,610
18	**Intermediate Production Level Capacity Costs**													
19	Southern - Franklin	3,053,631	3,057,021	3,056,255	3,541,434	3,052,407	2,469,707	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	31,208,455
20	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Intermediate Level Capacity Costs	3,038,839	3,042,229	3,041,463	3,526,642	3,037,615	2,454,915	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	31,030,951
23	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
24	Intermediate Level Jurisdictional Capacity Costs	2,209,327	2,211,792	2,211,235	2,563,975	2,208,437	1,784,797	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	22,560,432
25	**Peaking Production Level Capacity Costs**													
26	Chattahoochee	12,500	11,290	13,710	12,231	12,769	12,231	12,231	12,231	12,231	12,231	12,231	12,231	148,115
27	Vandolah (RRI)	2,925,728	2,887,475	1,995,855	1,940,723	2,792,514	5,785,174	-	-	-	-	-	-	18,297,490
28	Shady Hills Power Company LLC	1,965,615	1,973,145	1,406,700	1,363,500	1,968,900	3,840,480	3,881,947	3,881,947	1,811,575	1,363,927	1,363,927	1,968,252	26,729,915
29	Vandolah (NSG)	-	-	-	-	-	-	5,471,602	5,427,124	2,561,202	1,868,354	1,912,639	2,719,493	19,960,621
30	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Subtotal - Peaking Level Capacity Costs	4,903,844	4,871,910	3,386,276	3,316,454	4,774,183	9,637,885	9,365,780	9,321,302	4,385,008	3,244,512	3,288,997	4,699,976	65,136,132
32	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
33	Peaking Level Jurisdictional Capacity Costs	4,703,865	4,673,331	3,248,251	3,181,275	4,522,033	9,245,045	8,984,037	8,941,385	4,206,275	3,112,266	3,154,937	4,508,405	62,481,183
34	**Other Capacity Costs**													
35	Retail Wheeling	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(19,040)	(9,745)	(2,218)	(11,347)	(2,518)	(1,540)	(74,525)
36	Other Jurisdictional Capacity Costs	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(19,040)	(9,745)	(2,218)	(11,347)	(2,518)	(1,540)	(74,525)
37	**Subtotal Jurisd Capacity Costs (Line 17+24+33+36)**	34,028,038	33,935,646	32,474,900	32,806,333	34,415,695	37,967,523	37,404,972	33,901,635	29,174,072	26,070,933	28,122,434	26,174,418	380,477,600
38	**Nuclear Cost Recovery Clause Costs**													
39	Levy Costs	8,475,072	11,483,103	8,258,947	8,021,598	8,162,758	8,305,060	8,248,815	8,312,931	8,330,438	8,271,575	8,179,250	8,647,553	102,696,902
40	CR3 Uprate Costs	3,358,869	3,354,735	3,350,601	3,346,468	3,342,336	3,338,203	3,334,071	3,329,940	3,325,809	3,321,678	3,317,548	3,313,419	40,033,676
41	**Total NCRC Costs - Order No. PSC-12-0650-FOF-EI**	11,833,942	14,837,838	11,609,549	11,368,066	11,505,094	11,643,262	11,582,886	11,642,871	11,656,247	11,593,253	11,496,798	11,960,972	142,730,579
42	**Total Jurisdictional Capacity Costs (Line 37+41)**	45,861,980	48,774,484	44,084,449	44,174,399	45,920,789	49,610,786	48,987,858	45,544,506	40,830,319	38,664,187	39,619,232	40,135,390	523,208,179
43	**Capacity Revenues**													
44	Capacity Cost Recovery Revenues (net of tax)	37,233,908	36,928,525	36,311,578	36,378,448	43,163,088	48,265,348	51,923,538	54,322,575	54,369,943	47,492,236	41,168,481	39,591,723	529,147,389
45	Prior Period True-Up Provision Over/(Under) Recovery	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(10,485,622)
46	***Current Period Revenues (net of tax)***	36,360,106	36,054,723	35,437,776	37,502,644	42,289,286	47,391,546	51,049,737	53,448,773	53,496,141	46,618,434	40,294,679	38,717,921	518,661,767
47	**True-Up Provision**													
48	True-Up Provision - Over/(Under) Recov (Line 46-42)	(9,501,874)	(12,719,761)	(8,646,672)	(6,671,754)	(3,631,503)	(2,219,239)	2,082,079	7,904,287	12,665,822	6,954,247	575,447	(1,417,470)	(14,546,411)
49	Interest Provision for the Month	(1,425)	(2,785)	(3,569)	(3,599)	(3,341)	(2,887)	(3,211)	(3,791)	(4,374)	(4,955)	(5,633)	(6,120)	(45,590)
50	Current Cycle Balance - Over/(Under)	(9,503,299)	(22,225,844)	(30,876,086)	(37,551,438)	(41,186,283)	(43,408,409)	(41,349,541)	(33,449,055)	(20,787,617)	(13,838,325)	(13,268,411)	(14,592,001)	(14,592,001)
51	Prior Period Balance - Over/(Under) Recovered	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)
52	Prior Period Cumulative True-Up Collected/(Refunded)	873,802	1,747,604	2,621,405	3,495,207	4,369,009	5,242,811	6,116,613	6,990,415	7,864,216	8,738,018	9,611,820	10,485,622	10,485,622
53	Prior Period True-up Balance - Over/(Under)	(19,380,070)	(18,506,268)	(17,632,466)	(16,758,664)	(15,884,862)	(15,011,061)	(14,137,259)	(13,263,457)	(12,389,655)	(11,515,853)	(10,642,051)	(9,768,250)	(9,768,250)
54	**Net Capacity True-up Over/(Under) (Line 50+53)**	($28,883,369)	($40,732,112)	($48,508,552)	($54,310,103)	($57,071,145)	($58,419,470)	($55,486,799)	($46,712,522)	($33,177,272)	($25,354,179)	($23,910,463)	($24,360,251)	($24,360,251)

Duke Energy Florida
Variance Analysis
For the Year 2013

Docket No. 130001-EI
Exhibit__TGF-2, Part 2
Schedule E12-C

		Re-Projection Total	Original Projection Total	Variance Total
1	Capacity Revenues			
2	Capacity Cost Recovery Revenues (net of tax)	$529,147,389	$538,288,337	($9,140,948)
3	Prior Period True-Up Provision Over/(Under) Recovery	(10,485,622)	(10,485,622)	0
4	**Current Period Revenues (net of tax)**	518,661,767	527,802,715	9,140,948
5				
6	Capacity Costs			
7	Base Production Level Capacity Costs			
8	Auburndale Power Partners, L.P. (AUBRDLFC)	9,896,040	9,896,040	0
9	Auburndale Power Partners, L.P. (AUBSET)	43,335,107	43,335,108	(1)
10	Lake County (LAKCOUNT)	9,277,920	9,277,920	0
11	Lake Cogen Limited (LAKORDER)	26,150,313	26,150,313	0
12	Metro-Dade County (METRDADE)	15,424,530	15,842,419	(417,889)
13	Orange Cogen (ORANGECO)	35,490,064	35,490,060	4
14	Orlando Cogen Limited (ORLACOGL)	34,625,199	34,552,956	72,243
15	Pasco County Resource Recovery (PASCOUNT)	16,736,640	16,736,640	0
16	Pinellas County Resource Recovery (PINCOUNT)	39,840,480	39,840,480	0
17	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	68,504,529	68,504,532	(3)
18	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	9,570,012	9,611,352	(41,340)
19	Southern - Sherer	20,061,811	18,343,440	1,718,371
20	Subtotal - Base Level Capacity Costs	328,912,645	327,581,260	1,331,385
21	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
22	Base Level Jurisdictional Capacity Costs	305,510,510	304,273,849	1,236,661
23				
24	Intermediate Production Level Capacity Costs			
25	Southern - Franklin	31,208,455	25,956,000	5,252,455
26	Schedule H Capacity Sales - NSB & RCID	(177,504)	(131,304)	(46,200)
27	Subtotal - Intermediate Level Capacity Costs	31,030,951	25,824,696	5,206,255
28	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
29	Intermediate Level Jurisdictional Capacity Costs	22,560,432	18,775,330	3,785,102
30				
31	Peaking Production Level Capacity Costs			
32	Chattahoochee	148,115	151,612	(3,497)
33	Vandolah (RRI)	18,297,480	0	18,297,480
34	Shady Hills Power Company LLC	26,729,915	27,889,920	(1,160,005)
35	Vandolah (NSG)	19,960,621	36,740,467	(16,779,846)
36	Subtotal - Peaking Level Capacity Costs	65,136,132	64,782,000	354,132
37	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
38	Peaking Level Jurisdictional Capacity Costs	62,481,183	62,141,485	339,698
39				
40	Other Capacity Costs			
41	Retail Wheeling	(74,525)	(118,528)	44,003
42	Other Jurisdictional Capacity Costs	(74,525)	(118,528)	44,003
43				
44	**Subtotal Jurisdictional Capacity Costs (Line 22+29+38+42)**	390,477,600	385,072,136	5,405,464
45				
46	Nuclear Cost Recovery Clause Costs			
47	Levy Costs	102,696,902	102,696,902	0
48	CR3 Uprate Costs	40,033,676	40,033,676	0
49	**Total NCRC Costs - Order No. PSC-12-0650-FOF-EI**	142,730,579	142,730,579	0
50				
51	**Total Jurisdictional Capacity Costs (Line 44+49)**	533,208,179	527,802,715	5,405,464
52				
53	True-Up Provision			
54	True-Up Provision - Over/(Under) Recov (Line 4-51)	(14,546,411)	0	(14,546,411)
55	Interest Provision for the Month	(45,590)	0	(45,590)
56	Current Cycle Balance - Over/(Under)	(14,592,001)	0	(14,592,001)
57				
58	Prior Period Balance - Over/(Under) Recovered	(20,253,872)	(10,485,622)	(9,768,250)
59	Prior Period Cumulative True-Up Collected/(Refunded)	10,485,622	10,485,622	(0)
60	Prior Period True-up Balance - Over/(Under)	(9,768,250)	0	(9,768,250)
61				
62	**Net Capacity True-up Over/(Under) (Line 56+60)**	($24,360,251)	$0	($24,360,251)

CONFIDENTIAL – PART 2

REDACTED

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Auburndale Power Partners, L.P. (AUBRDLFC)	Jan-95	Dec-13	QF	Purch	17.00
2	Auburndale Power Partners, L.P. (AUBSET)	Aug-94	Dec-13	QF	Purch	114.18
3	Lake County (LAKCOUNT)	Jan-95	Jun-14	QF	Purch	12.75
4	Lake Cogen Limited (LAKORDER)	Jul-93	Jul-13	QF	Purch	110.00
5	Metro-Dade County (METRDADE)	Nov-91	Nov-13	QF	Purch	43.00
6	Orange Cogen (ORANGECO)	Jul-95	Dec-13	QF	Purch	74.00
7	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	79.20
8	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
9	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
10	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
11	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Dec-23	QF	Purch	39.60
12	Southern Power - Scherer 3	Jun-10	May-16	Other	Purch	73.00
13	Southern Power - Franklin	Jun-10	May-16	Other	Purch	350.00
14	Schedule H Capacity - New Smyrna Beach	[redacted]	see note (1)	Other	Sale	[redacted]
15	Chattahoochee			Other	Purch	
16	Vandolah (NSG)			Other	Puch	
17	Shady Hills Tolling Agreement			Other	Purch	

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Duke Energy Florida or NSB upon 1 year's written notice.

Docket 130001-EI
Exhibit No. ____(TGF-3)
Part 1

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2014

PART 1 – 2014 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 26
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Thomas G. Foster - TGF-3

PROJECTED MARKET PRICE BY FUEL TYPE

Month	Heavy Oil 1.7# SO_2 [1]		Light Oil		Coal Crystal River 1 & 2		Coal Crystal River 4 & 5		Natural Gas
	$/barrel	$/mmbtu	$/barrel	$/mmbtu	$/ton	$/mmbtu	$/ton	$/mmbtu	$/mmbtu
Jan 2014	N/A	N/A	119.86	20.68	106.09	4.34	72.90	3.10	3.76
Feb 2014	N/A	N/A	119.56	20.63	106.14	4.34	72.12	3.07	3.76
Mar 2014	N/A	N/A	118.93	20.52	106.47	4.35	71.35	3.04	3.73
Apr 2014	N/A	N/A	118.20	20.39	106.72	4.36	69.25	2.95	3.68
May 2014	N/A	N/A	117.56	20.28	103.97	4.26	67.62	2.89	3.70
Jun 2014	N/A	N/A	117.15	20.21	101.97	4.19	66.32	2.84	3.73
Jul 2014	N/A	N/A	116.70	20.13	100.22	4.12	65.43	2.81	3.76
Aug 2014	N/A	N/A	116.53	20.11	98.96	4.08	65.11	2.80	3.78
Sep 2014	N/A	N/A	116.29	20.06	99.00	4.08	64.90	2.79	3.78
Oct 2014	N/A	N/A	115.58	19.94	100.89	4.15	64.90	2.79	3.80
Nov 2014	N/A	N/A	114.93	19.83	101.91	4.19	65.18	2.81	3.88
Dec 2014	N/A	N/A	114.30	19.72	103.32	4.25	65.17	2.81	4.05
Average	N/A	N/A	116.88	20.17	102.69	4.22	67.03	2.87	3.79

[1] Heavy Oil 1.7# SO_2 pricing is reflected as "N/A" because DEF is not forecasting any Heavy Oil usage in the projected period of January 2014 - December 2014

Light Oil: The above base market oil price forecasts are the NYMEX forwards. Oil prices projected within the fuel forecast are based on expected contract structures and specifications, and incorporate current hedge positions and transportation costs.

Coal: Coal price projections are based on the current coal supply, transportation agreements, and forecasted deliveries. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2. Crystal River 4 and 5 have operating scrubbers which allow for consideration of higher sulfur coal.

Natural Gas: The base market natural gas price forecast is the NYMEX Henry Hub forwards. This table includes natural gas market commodity prices only; however, the fuel forecast incorporates hedges and transportation costs. Forecast prices are based on expected contract specifications and incorporate current hedge positions. Firm transportation costs for Florida Gas Transmission and Gulfstream pipeline are based on expected tariff rates and/or negotiated rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

Docket 130001-EI
Exhibit No. ____(TGF-3)
Part 2

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

JANUARY THROUGH DECEMBER 2014

PART 2 - 2014 FUEL COST RECOVERY SCHEDULES

Schedule E1 – Fuel Cost Recovery Clause Calculation

Schedule E1-A – Calculation of Total True-up

Schedule E1-B – Calculation of Prior Year Estimated True-up

Schedule E1-C – Calculation of GPIF & True-up Factors

Schedule E1-D – Calculation of Levelized Fuel Adjustment Factors

Schedule E1-E – Calculation of Factors for Metering Voltage and Time of Use

Schedule E1-F – Calculation of Jurisdictional Delivery Loss Multipliers

Schedule E2 – Fuel Cost Recovery Clause Calculation by Month

Schedule E3 – Generating System Comparative Data

Schedule E4 – System Net Generation & Fuel Cost by Month

Schedule E5 – Inventory Analysis

Schedule E6 – Fuel Cost of Power Sold

Schedule E7 – Purchased Power

Schedule E8 – Energy Payments to Qualifying Facilities

Schedule E9 – Economy Energy Purchases

Schedule E10 – Residential Bill Comparison

Calculation of Inverted Residential Fuel Rate

Schedule H1 – Generating System Comparative Data

Docket No. 130001-EI
Schedule E1
Exhibit TGF-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2014

				DOLLARS		MWH		CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)			1,415,304,375		34,832,378		4.06319
2.	Spent Nuclear Fuel Disposal Cost			0		0	*	0.00000
3.	Coal Car Investment			0		0		0.00000
4.	Adjustment to Fuel Cost			(128,673,569)		0		0.00000
5.	TOTAL COST OF GENERATED POWER			1,286,630,806		34,832,378		3.69378
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)			193,909,321		3,301,834		5.87278
7.	Energy Cost of Economy Purchases (E9)			13,558,753		201,860		6.71691
8.	Payments to Qualifying Facilities (E8)			137,578,568		3,019,852		4.55580
9.	TOTAL COST OF PURCHASED POWER			345,046,642		6,523,546		5.28925
10.	TOTAL AVAILABLE MWH					41,355,924		
11.	Fuel Cost of Economy Sales	(E6)		(3,510,887)		(91,711)		3.82821
11a.	Gain on Economy Sales	(E6)		(667,252)		(91,711)	*	0.72756
12.	Fuel Cost of Stratified Sales	(E6)		(37,314,237)		(975,861)		3.82372
13.	TOTAL FUEL COST AND GAINS ON POWER SALES			(41,492,376)		(1,067,572)		3.88661
14.	Net Inadvertent Interchange							
15.	TOTAL FUEL AND NET POWER TRANSACTIONS			1,590,185,072		40,288,352		3.94701
16.	Net Unbilled			957,848	*	(24,268)		0.00253
17.	Company Use			5,683,694	*	(144,000)		0.01500
18.	T & D Losses			87,813,751	*	(2,224,817)		0.23173
19.	Adjusted System Sales			1,590,185,072		37,895,267		4.19626
20.	Wholesale Sales (Excluding Supplemental Sales)			(9,546,966)		(230,488)		4.14207
21.	Jurisdictional Sales			1,580,638,106		37,664,779		4.19659
22.	Jurisdictional Sales Adjusted for Line Losses x		1.0015	1,583,009,063		37,664,779		4.20289
23.	Prior Period True-Up (Sch E1-A)			33,195,183		37,664,779		0.08813
24.	Total Jurisdictional Fuel Cost			1,616,204,246		37,664,779		4.29102
25.	Revenue Tax Factor			1,163,667				1.00072
26.	Fuel Cost Adjusted for Taxes			1,617,367,913		37,664,779		4.29411
27.	GPIF **			3,262,447		37,664,779		0.00866
28.	Fuel Factor Adjusted for taxes including GPIF			1,620,630,360		37,664,779		4.30277
29.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)							4.303

* For Informational Purposes Only

** Based on Jurisdictional Sales

Duke Energy Florida
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January through December 2014

1.	Actual Over/(Under) Recovery January - December 2012. **(** Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec '12 **)**	$	(217,577,600)
2.	Projected (Over)/Under Recovery January - December 2012 . (Refunded)/Collected January - December 2012 . **(** Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec '12 **)**	$	145,366,912
3.	Estimated Over/(Under) Recovery January - December 2013 **(** Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec '13 **)**	$	39,015,505
4.	Total Over/(Under) Recovery to be Included in the January - December 2013 Projected Period **(** Lines 1 through 3 **)**	$	(33,195,183)
5.	Jurisdictional mWh Sales (Projected Period)	mWh	37,664,779
6.	True-Up Factor (Line 4 / Line 5)	Cents/kWh	0.088

CALCULATION OF ESTIMATED TRUE-UP
(12 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JAN ESTIMATED	FEB ESTIMATED	MAR ESTIMATED	APR ESTIMATED	MAY ESTIMATED	JUN ESTIMATED	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 109,697,450	$ 98,055,406	$ 102,409,303	$ 109,857,132	$ 131,525,689	$ 133,094,832	$ 684,639,814
	2	Fuel Cost of Power Sold	(2,803,915)	(3,204,332)	(1,573,292)	(2,397,957)	(3,953,778)	(3,147,549)	(17,080,824)
	3	Fuel Cost of Purchased Power	10,366,631	8,730,628	13,494,162	12,905,539	16,967,603	23,495,283	85,959,846
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	12,290,083	11,165,902	11,080,558	9,903,257	12,009,955	11,675,501	68,125,257
	4	Energy Cost of Economy Purchases	633,441	557,310	1,061,389	1,184,454	1,459,788	1,406,780	6,303,162
	5	Adjustments to Fuel Cost	(9,721,268)	(10,823,336)	(10,801,583)	(10,796,158)	(10,802,668)	(10,801,583)	(63,746,595)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	120,462,423	104,481,578	115,670,538	120,656,267	147,206,589	155,723,264	764,200,660
B	1	Jurisdictional KWH Sales	2,853,337	2,664,980	2,618,503	2,721,614	2,943,262	3,503,630	17,305,326
	2	Non-Jurisdictional KWH Sales	15,639	18,564	12,889	12,147	14,850	17,380	91,469
	3	TOTAL SALES (Lines B1 + B2)	2,868,976	2,683,544	2,631,392	2,733,761	2,958,112	3,521,010	17,396,795
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.45%	99.31%	99.51%	99.56%	99.50%	99.51%	99.47%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	122,684,313	114,585,568	112,587,206	117,020,648	126,550,799	150,644,820	744,073,354
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(16,597,590)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(1,631,226)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	119,646,177	111,547,432	109,549,070	113,982,512	123,512,663	147,606,684	725,844,538
	4	Fuel & Net Power Transactions (Line A6)	120,462,423	104,481,578	115,670,538	120,656,267	147,206,589	155,723,264	764,200,660
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	119,979,579	103,916,296	115,276,408	120,305,568	146,690,262	155,192,661	761,360,774
	6	Over/(Under) Recovery (Line C3 - Line C5)	(333,402)	7,631,135	(5,727,338)	(6,323,056)	(23,177,599)	(7,585,977)	(35,516,236)
	7	Interest Provision	(1,597)	(1,276)	(1,090)	(1,253)	(1,852)	(2,483)	(9,552)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(334,999)	7,629,859	(5,728,428)	(6,324,309)	(23,179,452)	(7,588,459)	(35,525,788)
	9	Plus: Prior Period Balance	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)
	10	Plus: Cumulative True-Up Provision	2,766,265	5,532,530	8,298,795	11,065,060	13,831,325	16,597,590	16,597,590
	11	Subtotal Prior Period True-up	(30,428,918)	(27,662,653)	(24,896,388)	(22,130,123)	(19,363,858)	(16,597,593)	(16,597,593)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($30,763,917)	($20,367,793)	($23,329,956)	($26,888,000)	($47,301,187)	($52,123,382)	($52,123,382)

CALCULATION OF ESTIMATED TRUE-UP
(12 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 139,588,791	$ 143,678,496	$ 131,196,571	$ 114,775,399	$ 96,807,605	$ 104,617,700	$ 1,415,304,375
	2	Fuel Cost of Power Sold	(4,414,177)	(5,997,006)	(4,695,441)	(4,385,374)	(3,226,757)	(1,692,798)	(41,492,376)
	3	Fuel Cost of Purchased Power	23,165,512	23,634,893	20,625,684	17,745,201	12,332,688	10,445,497	193,909,321
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	11,730,800	11,857,186	11,445,495	11,414,923	10,688,803	12,316,104	137,578,568
	4	Energy Cost of Economy Purchases	1,302,455	1,234,821	1,429,756	1,484,812	1,024,770	778,977	13,558,753
	5	Adjustments to Fuel Cost	(10,817,889)	(10,824,426)	(10,827,697)	(10,829,879)	(10,821,157)	(10,805,926)	(128,673,569)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	160,555,492	163,583,964	149,174,368	130,205,083	106,805,953	115,659,554	1,590,185,072
B	1	Jurisdictional KWH Sales	3,674,816	3,817,582	3,828,744	3,358,467	2,905,863	2,773,981	37,664,779
	2	Non-Jurisdictional KWH Sales	23,785	26,898	28,347	25,523	19,658	14,808	230,488
	3	TOTAL SALES (Lines B1 + B2)	3,698,601	3,844,480	3,857,091	3,383,990	2,925,521	2,788,789	37,895,267
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.36%	99.30%	99.27%	99.25%	99.33%	99.47%	99.39%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	158,005,268	164,143,746	164,623,677	144,403,278	124,942,762	119,272,260	1,619,464,346
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,268)	(33,195,183)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,866)	(3,262,447)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	154,967,132	161,105,610	161,585,541	141,365,142	121,904,626	116,234,126	1,583,006,715
	4	Fuel & Net Power Transactions (Line A6)	160,555,492	163,583,964	149,174,368	130,205,083	106,805,953	115,659,554	1,590,185,072
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	159,767,228	162,682,534	148,307,523	129,422,388	106,249,488	115,219,128	1,583,009,064
	6	Over/(Under) Recovery (Line C3 - Line C5)	(4,800,097)	(1,576,924)	13,278,018	11,942,755	15,655,138	1,014,998	(2,348)
	7	Interest Provision	(2,654)	(2,675)	(2,245)	(1,476)	(648)	(93)	(19,344)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(4,802,751)	(1,579,599)	13,275,773	11,941,278	15,654,489	1,014,904	(21,692)
	9	Plus: Prior Period Balance	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)
	10	Plus: Cumulative True-Up Provision	19,363,855	22,130,120	24,896,385	27,662,650	30,428,915	33,195,183	33,195,183
	11	Subtotal Prior Period True-up	(13,831,328)	(11,065,063)	(8,298,798)	(5,532,533)	(2,766,268)	-	-
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($54,159,868)	($52,973,202)	($36,931,164)	($22,223,620)	($3,802,866)	($21,692)	($21,692)

Duke Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January through December 2014

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	3,262,447
	B. True-Up (Over) / Under Recovery	$	33,195,183
2.	JURISDICTIONAL mWh SALES	mWh	37,664,779
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.009
	B. True-Up Factor	Cents/kWh	0.088

Duke Energy Florida
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January through December 2014

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 22)	$	1,583,009,063	
1a.	Prior Period True-up (E1, Line 23)	$	33,195,183	
2.	Regulatory Assessment Fee (E1, Line 25)	$	1,163,667	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 27)	$	3,262,447	
4.	Total amount to be Recovered	$	1,620,630,360	
5.	Jurisdictional Sales (January - December 2014)		37,664,779	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		4.303	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		37,616,661	mWh
	LEVELIZED FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):			
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)		4.308	Cents/kWh
9.	Fuel Factor Adjustment pursuant to 2013 Revised and Restated Stipulation and Settlement Agreement		0.100	Cents/kWh
10.	Adjusted Fuel Factor at Secondary Meterting (Line 8 + Line 9)		4.408	Cents/kWh
11.	Fuel Factor at Primary Metering		4.364	Cents/kWh
12.	Fuel Factor at Transmission Metering		4.320	Cents/kWh
	LEVELIZED FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):			
13.	2012 Settlement Agreement Refund (per Order No. PSC-12-0104-FOF-EI)*	$	(9,400,000)	
14.	Interest Amortization on Settlement Agreement Refund*	$	(51,863)	
15.	Applicable Jurisdictional Sales at Secondary Metering**		19,379,756	mWh
16.	Fuel Factor at Secondary Metering Rate Adjustment (Line 13 + Line 14 / Line 15 / 10)		(0.049)	Cents/kWh
17.	Fuel Factor at Secondary Metering (Line 10 + Line 16)		4.359	Cents/kWh
	LEVELIZED FUEL FACTORS (only GS-1, GST-1 & GS-2):			
18.	2012 Settlement Agreement Refund (per Order No. PSC-12-0104-FOF-EI)*	$	(600,000)	
19.	Interest Amortization on Settlement Agreement Refund*	$	(3,310)	
20.	Applicable Jurisdictional Sales at Secondary Metering**		1,384,634	mWh
21.	Fuel Factor at Secondary Metering Rate Adjustment (Line 18 + Line 19 / Line 20 / 10)		(0.044)	Cents/kWh
22.	Fuel Factor at Secondary Metering (Line10 + Line 21)		4.364	Cents/kWh
23.	Fuel Factor at Primary Metering		4.320	Cents/kWh
24.	Fuel Factor at Transmission Metering		4.277	Cents/kWh
	TIERED FUEL FACTORS:			
25.	Fuel Factor - First Tier (0-1000 kWh)		4.077	Cents/kWh
26.	Fuel Factor - Second Tier (Over 1000 kWh)		5.077	Cents/kWh

* The 2012 Settlement Agreement refunds and associated interest incuded on lines 13-14 and 18-19 are consistent with and included in the 2013 Revised and Restated Stipulation and Settlement Agreement, which is subject to approval by the Commission.

** Applicable Jurisdictional Sales at Secondary Metering utilized in the calculation of the 2012 Settlement Agreement Refund Fuel Factor Adjustment (lines 15 & 20) are a subset of the Effective Jurisdictional Sales reported above on line 7.

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	33,218,915	33,218,915
Distribution Primary	4,079,897	4,039,098
Transmission	365,967	358,648
Total	37,664,779	37,616,661

Duke Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January through December 2014

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	----------Time of Use---------- On-Peak Multiplier 1.291	Off-Peak Multiplier 0.858
	FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):					
1.	Distribution Secondary	--	--	4.408	5.691	3.782
2.	Distribution Primary	--	--	4.364	5.634	3.744
3.	Transmission	--	--	4.320	5.577	3.707
4.	Lighting Service	--	--	4.139	--	--
	Line 4 calculated at secondary rate of 4.408 * (18.7% * On-Peak Multiplier 1.291 + 81.3% * Off-Peak Multiplier 0.858).					
	FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):					
5.	Distribution Secondary	4.077	5.077	4.359	5.627	3.740
	FUEL FACTORS (only GS-1, GST-1 & GS-2):					
6.	Distribution Secondary	--	--	4.364	5.634	3.744
7.	Distribution Primary	--	--	4.320	5.577	3.707
8.	Transmission	--	--	4.277	5.522	3.670

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-14	943,942	38,695,756	4.099	2,186,482	69,335,693	3.171	3,130,424	108,031,448	3.451
Feb-14	746,267	29,976,426	4.017	2,008,805	63,980,043	3.185	2,755,072	93,956,469	3.410
Mar-14	731,189	26,957,363	3.687	2,235,527	74,571,902	3.336	2,966,716	101,529,265	3.422
Apr-14	1,097,848	51,851,964	4.723	1,956,957	65,579,300	3.351	3,054,805	117,431,264	3.844
May-14	1,340,577	100,364,691	7.487	2,338,227	84,613,516	3.619	3,678,804	184,978,207	5.028
Jun-14	1,424,635	71,016,802	4.985	2,641,126	91,157,952	3.451	4,065,761	162,174,754	3.989
Jul-14	1,566,806	80,448,844	5.135	2,616,191	89,027,790	3.403	4,182,997	169,476,634	4.052
Aug-14	1,449,388	90,662,803	6.255	2,817,534	97,909,543	3.475	4,266,922	188,572,346	4.419
Sep-14	1,448,413	77,758,876	5.369	2,482,395	80,573,739	3.246	3,930,808	158,332,614	4.028
Oct-14	1,238,447	65,930,950	5.324	2,078,761	74,688,432	3.593	3,317,208	140,619,382	4.239
Nov-14	661,446	23,903,790	3.614	2,169,550	77,422,505	3.569	2,830,996	101,326,295	3.579
Dec-14	892,102	33,978,468	3.809	2,192,000	71,830,000	3.277	3,084,102	105,808,469	3.431
TOTAL	13,541,060	691,546,732	5.107	27,723,555	940,690,416	3.393	41,264,615	1,632,237,148	3.956

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST			
WEIGHTING MULTIPLIER	1.291	0.858	1.000

Duke Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2012
Estimated for the Period of : January through December 2014

		Energy Delivered @ Billing Level							
		Billed MWH	Unbilled MWH	Total MWH	% of Total	Delivery Efficiency	Energy Required @ Source Level	% of Total	Jurisdictional Loss Multiplier
Retail									
Transmission		336,763	2,768	339,531		0.9844331	344,900		
Distribution Primary		3,994,133	32,827	4,026,960		0.9744331	4,132,619		
Distribution Secondary		32,050,561	263,420	32,313,981		0.9401722	34,370,280		
Total Retail		36,381,457	299,015	36,680,472	97.01%	0.9442098	38,847,799	97.15%	1.00150
						5.58%			
Wholesale									
Generation Level		753,841	(40,142)	713,699		1.0000000	713,699		
Transmission		395,998	(6,112)	389,886		0.9844331	396,051		
Distribution Primary		26,868	771	27,639		0.9744331	28,364		
Distribution Secondary		-	-	-			-		
Total Wholesale		1,176,707	(45,483)	1,131,224	2.99%	0.9939457	1,138,115	2.85%	0.95139
						0.61%			
Subtotal Class		37,558,164	253,532	37,811,696	100.00%	0.9456254	39,985,914	100.00%	1.00000
						5.44%			
Non-Class									
SEPA	Transmission	83,419	-	83,419		0.9844331	84,738		
Homestead - Base	Generation	197,004	1,802	198,806		1.0000000	198,806		
SECI - Base	Generation	84,165	(7,601)	76,564		1.0000000	76,564		
Homestead - Intermediate	Generation	-	-	-		1.0000000	-		
Reedy Creek - Base	Generation	43,313	396	43,709		1.0000000	43,709		
Seminole Elect. Coop	Generation	56,399	(5,093)	51,306		1.0000000	51,306		
Tallahassee - Base	Transmission	100,140	916	101,056		0.9844331	102,654		
Gainesville - Base	Generation	26,404	241	26,645		1.0000000	26,645		
Interchange	Generation	534,580	-	534,580		1.0000000	534,580		
Company Use	Secondary	149,355	-	149,355		0.9401722	158,859		
Total Non-Class		1,274,779	(9,339)	1,265,440			1,277,861		
Total System		38,832,943	244,193	39,077,136		0.947008	41,263,775		

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2014

			Estimated Jan-14	Estimated Feb-14	Estimated Mar-14	Estimated Apr-14	Estimated May-14	Estimated Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	TOTAL
1	Fuel Cost of System Net Generation		$109,697,450	$98,055,406	$102,409,303	$109,857,132	$131,525,689	$133,094,832	$139,588,791	$143,678,496	$131,196,571	$114,775,399	$96,807,605	$104,617,700	$1,415,304,375
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(9,721,268)	(10,823,336)	(10,801,583)	(10,796,158)	(10,802,668)	(10,801,583)	(10,817,889)	(10,824,426)	(10,827,697)	(10,829,879)	(10,821,157)	(10,805,926)	(128,673,569)
2	Fuel Cost of Power Sold		(373,584)	(781,759)	(27,975)	(48,483)	(962,079)	(7,485)	(124,621)	(1,087,424)	(6,071)	(47,591)	(41,270)	(2,545)	(3,510,887)
2a	Gains on Power Sales		(78,453)	(164,169)	(5,875)	(10,182)	(202,036)	(1,572)	(26,170)	(228,359)	(1,275)	(9,994)	(8,667)	69,500	(667,252)
2b	Fuel Cost of Stratified Sales		(2,351,878)	(2,258,404)	(1,539,442)	(2,339,292)	(2,789,663)	(3,138,492)	(4,263,386)	(4,681,223)	(4,688,095)	(4,327,789)	(3,176,820)	(1,759,753)	(37,314,237)
3	Fuel Cost of Purchased Power (Excl Economy)		10,366,631	8,730,628	13,494,162	12,905,539	16,967,603	23,495,283	23,165,512	23,634,893	20,625,684	17,745,201	12,332,688	10,445,497	193,909,321
3a	Energy Payments to Qualifying Facilities		12,290,083	11,165,902	11,080,558	9,903,257	12,009,955	11,675,501	11,730,800	11,857,186	11,445,495	11,414,923	10,688,803	12,316,104	137,578,568
4	Energy Cost of Economy Purchases		633,441	557,310	1,061,389	1,184,454	1,459,788	1,406,780	1,302,455	1,234,821	1,429,756	1,484,812	1,024,770	778,977	13,558,753
5	Total System Fuel & Net Power Transactions		$120,462,423	$104,481,578	$115,670,538	$120,656,267	$147,206,589	$155,723,264	$160,555,492	$163,583,964	$149,174,368	$130,205,083	$106,805,953	$115,659,554	$1,590,185,072
6	Jurisdictional mWh Sold		2,853,337	2,664,980	2,618,503	2,721,614	2,943,262	3,503,630	3,674,816	3,817,582	3,828,744	3,358,467	2,905,863	2,773,981	37,664,779
7	Jurisdictional % of Total Sales		99.45%	99.31%	99.51%	99.56%	99.50%	99.51%	99.36%	99.30%	99.27%	99.25%	99.33%	99.47%	99.39%
8	Jurisdicitonal Fuel & Net Power Transactions		119,799,879	103,760,655	115,103,752	120,125,379	146,470,556	154,960,220	159,527,936	162,438,876	148,085,395	129,228,545	106,090,353	115,046,558	1,580,638,106
9	Jurisdictional Loss Multiplier		1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150
10	Jurisdictional Fuel & Net Power Transactions		119,979,579	103,916,296	115,276,408	120,305,568	146,690,262	155,192,661	159,767,228	162,682,534	148,307,523	129,422,388	106,249,488	115,219,128	1,583,009,064
11	Adjusted System Sales	mWh	2,868,976	2,683,544	2,631,392	2,733,761	2,958,112	3,521,010	3,698,601	3,844,480	3,857,091	3,383,990	2,925,521	2,788,789	37,895,267
12	System Cost per kWh Sold	c/kWh	4.1989	3.8934	4.3958	4.4136	4.9764	4.4226	4.3410	4.2550	3.8675	3.8477	3.6508	4.1473	4.1963
13	Jurisdictional Loss Multiplier	x	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.00150
14	Jurisdictional Cost per kWh Sold	c/kWh	4.2049	3.8993	4.4024	4.4204	4.9839	4.4295	4.3476	4.2614	3.8735	3.8536	3.6564	4.1536	4.2029
15	Prior Period True-Up	+	0.0970	0.1038	0.1056	0.1016	0.0940	0.0790	0.0753	0.0725	0.0723	0.0824	0.0952	0.0997	0.0881
16	Total Jurisdictional Fuel Expense	c/kWh	4.3018	4.0031	4.5080	4.5220	5.0779	4.5084	4.4229	4.3339	3.9458	3.9360	3.7516	4.2533	4.2910
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kWh	4.3049	4.0060	4.5113	4.5253	5.0816	4.5117	4.4261	4.3370	3.9486	3.9388	3.7543	4.2564	4.2941
19	GPIF	+	0.0095	0.0102	0.0104	0.0100	0.0092	0.0078	0.0074	0.0071	0.0071	0.0081	0.0094	0.0098	0.0087
20	Total Recovery Factor (rounded .001)	c/kWh	4.314	4.016	4.522	4.535	5.091	4.519	4.433	4.344	3.956	3.947	3.764	4.266	4.303

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2014

			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		1,230,546	861,982	1,203,703	1,484,156	5,359,777	2,071,944	12,212,110
3	COAL		35,565,154	28,648,636	31,000,046	36,640,161	39,248,525	38,586,880	209,689,402
4	GAS		72,901,750	68,544,788	70,205,554	71,732,815	86,917,387	92,436,008	462,738,302
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	109,697,450	98,055,406	102,409,303	109,857,132	131,525,689	133,094,832	684,639,814
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		903	475	414	1,473	13,456	3,365	20,086
10	COAL		991,196	790,357	842,117	1,011,146	1,070,630	1,084,466	5,789,912
11	GAS		1,703,555	1,594,548	1,636,695	1,605,940	2,069,529	2,261,943	10,872,210
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,695,654	2,385,380	2,479,226	2,618,559	3,153,615	3,349,774	16,682,208
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	8,821	6,018	8,685	10,886	40,906	15,568	90,884
17	COAL	TON	436,874	349,157	371,496	454,678	486,835	491,221	2,590,261
18	GAS	MCF	13,094,387	12,099,265	12,472,278	12,574,756	16,403,942	17,713,816	84,358,444
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		0	0	0	0	0	0	0
22	LIGHT OIL		51,127	34,893	50,334	63,107	237,067	90,244	526,771
23	COAL		10,338,262	8,263,049	8,807,998	10,758,667	11,519,110	11,591,679	61,278,765
24	GAS		13,094,387	12,099,265	12,472,278	12,574,756	16,403,942	17,713,816	84,358,444
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	23,483,776	20,397,207	21,330,610	23,396,530	28,160,119	29,395,739	146,163,980
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.03%	0.02%	0.02%	0.06%	0.43%	0.10%	0.12%
30	COAL		36.77%	33.13%	33.97%	38.62%	33.95%	32.37%	34.71%
31	GAS		63.20%	66.85%	66.02%	61.33%	65.62%	67.53%	65.17%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	139.50	143.24	138.60	136.33	131.03	133.09	134.37
37	COAL	$/TON	81.41	82.05	83.45	80.58	80.62	78.55	80.95
38	GAS	$/MCF	5.57	5.67	5.63	5.70	5.30	5.22	5.49
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	LIGHT OIL		24.07	24.70	23.92	23.52	22.61	22.96	23.18
43	COAL		3.44	3.47	3.52	3.41	3.41	3.33	3.42
44	GAS		5.57	5.67	5.63	5.71	5.30	5.22	5.49
45	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	4.67	4.81	4.80	4.70	4.67	4.53	4.68
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		56,619	73,458	121,579	42,842	17,618	26,818	26,226
50	COAL		10,430	10,455	10,459	10,640	10,759	10,689	10,584
51	GAS		7,687	7,588	7,620	7,830	7,926	7,831	7,759
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,712	8,551	8,604	8,935	8,929	8,775	8,762
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		136.27	181.47	290.75	100.76	39.83	61.57	60.80
57	COAL		3.59	3.62	3.68	3.62	3.67	3.56	3.62
58	GAS		4.28	4.30	4.29	4.47	4.20	4.09	4.26
59	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	4.07	4.11	4.13	4.20	4.17	3.97	4.10

Docket No. 130001-EI
Schedule E3 (Sheet 2)
Exhibit TGF-3, Part 2

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2014

			Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		3,075,537	3,130,137	1,555,189	2,274,850	848,820	976,007	24,072,649
3	COAL		39,296,182	39,851,367	37,982,278	30,772,346	27,019,808	30,222,011	414,833,394
4	GAS		97,217,072	100,696,992	91,659,104	81,728,203	68,938,977	73,419,682	976,398,332
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	139,588,791	143,678,496	131,196,571	114,775,399	96,807,605	104,617,700	1,415,304,375
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		6,302	6,864	2,526	4,297	107	42	40,224
10	COAL		1,108,179	1,133,700	1,084,738	909,502	779,031	909,278	11,714,340
11	GAS		2,375,352	2,448,849	2,204,559	1,842,906	1,604,209	1,729,729	23,077,814
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,489,833	3,589,413	3,291,823	2,756,705	2,383,347	2,639,049	34,832,378
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	23,431	23,873	11,626	17,309	6,141	7,190	180,452
17	COAL	TON	504,335	515,293	493,941	417,832	346,604	405,523	5,273,789
18	GAS	MCF	18,716,332	19,499,283	17,357,273	14,828,803	12,514,788	13,268,196	180,543,119
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		0	0	0	0	0	0	0
22	LIGHT OIL		135,781	138,377	67,394	100,317	35,604	41,677	1,045,921
23	COAL		11,888,643	12,131,475	11,613,891	9,766,427	8,131,943	9,473,774	124,284,918
24	GAS		18,716,332	19,499,283	17,357,273	14,828,803	12,514,788	13,268,196	180,543,119
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	30,740,756	31,769,135	29,038,558	24,695,547	20,682,335	22,783,647	305,873,958
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.18%	0.19%	0.08%	0.16%	0.00%	0.00%	0.12%
30	COAL		31.75%	31.59%	32.95%	32.99%	32.69%	34.46%	33.63%
31	GAS		68.07%	68.22%	66.97%	66.85%	67.31%	65.54%	66.25%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	131.26	131.12	133.77	131.43	138.22	135.75	133.40
37	COAL	$/TON	77.92	77.34	76.90	73.65	77.96	74.53	78.66
38	GAS	$/MCF	5.19	5.16	5.28	5.51	5.51	5.53	5.41
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	LIGHT OIL		22.65	22.62	23.08	22.68	23.84	23.42	23.02
43	COAL		3.31	3.29	3.27	3.15	3.32	3.19	3.34
44	GAS		5.19	5.16	5.28	5.51	5.51	5.53	5.41
45	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	4.54	4.52	4.52	4.65	4.68	4.59	4.63
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		21,546	20,160	26,680	23,346	332,747	992,301	26,002
50	COAL		10,728	10,701	10,707	10,738	10,439	10,419	10,610
51	GAS		7,879	7,963	7,873	8,046	7,801	7,671	7,823
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,809	8,851	8,821	8,958	8,678	8,633	8,781
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		48.80	45.60	61.57	52.94	793.29	2323.83	59.85
57	COAL		3.55	3.52	3.50	3.38	3.47	3.32	3.54
58	GAS		4.09	4.11	4.16	4.43	4.30	4.24	4.23
59	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	4.00	4.00	3.99	4.16	4.06	3.96	4.06

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-14

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3 805	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1 376	28,199	10.1	92.10	45.5	10,832	COAL	12,492	TONS	24.45	305,453	1,476,223	5.24
3	CRYSTAL RIVER	2 500	119,642	32.2	93.66	33.7	10,965	COAL	53,653	TONS	24.45	1,311,924	5,842,853	4.88
4	CRYSTAL RIVER	4 732	412,697	75.8	92.14	79.4	10,422	COAL	182,847	TONS	23.52	4,301,215	13,939,489	3.38
5	CRYSTAL RIVER	5 712	430,658	81.3	93.56	84.6	10,263	COAL	187,882	TONS	23.52	4,419,670	14,306,589	3.32
6	ANCLOTE	1 517	0	0.0	92.30	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2 521	0	0.0	94.81	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1 30	0	0.0	96.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2 30	0	0.0	94.52	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3 73	0	0.0	96.13	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1 517	16,522	4.3	92.30	33.6	12,008	GAS	198,399	MCF	1.00	198,399	1,986,374	12.02
12	ANCLOTE	2 521	74,997	19.3	94.81	20.0	12,313	GAS	923,443	MCF	1.00	923,443	5,143,215	6.86
13	AVON PARK	1-2 69	105	0.2	81.29	50.7	15,514	GAS	1,629	MCF	1.00	1,629	24,833	23.65
14	BARTOW	1-4 228	576	0.3	72.50	23.0	13,313	GAS	7,668	MCF	1.00	7,668	50,657	8.79
15	BARTOW CC	1 1279	675,754	71.0	95.42	74.1	7,234	GAS	4,888,528	MCF	1.00	4,888,528	25,947,526	3.84
16	DEBARY	1-10 785	2,084	0.4	95.97	10.3	12,542	GAS	26,138	MCF	1.00	26,138	286,503	13.75
17	HIGGINS	1-4 129	395	0.4	88.79	21.9	16,580	GAS	6,549	MCF	1.00	6,549	45,784	11.59
18	HINES CC	1-4 2,204	833,284	50.8	93.96	19.6	7,277	GAS	6,063,907	MCF	1.00	6,063,907	33,776,504	4.05
19	INT CITY	1-14 1,186	8,994	1.1	89.17	7.0	12,626	GAS	113,561	MCF	1.00	113,561	839,843	9.34
20	SUWANNEE	1 67	908	1.8	93.55	0.0	13,002	GAS	11,806	MCF	1.00	11,806	123,361	13.59
21	SUWANNEE	2 66	528	1.1	95.16	28.6	14,758	GAS	7,792	MCF	1.00	7,792	62,710	11.88
22	SUWANNEE	3 67	24,495	49.1	99.68	51.1	11,683	GAS	286,173	MCF	1.00	286,173	1,317,955	5.38
23	TIGER BAY CC	1 225	29,662	17.7	90.32	91.5	7,637	GAS	226,530	MCF	1.00	226,530	1,590,759	5.36
24	UNIV OF FLA. CC	1 47	35,251	100.8	98.71	102.2	9,426	GAS	332,264	MCF	1.00	332,264	1,705,726	4.84
25	AVON PARK	1-2 69	0	0.0	81.29	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4 228	0	0.0	72.50	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4 231	132	0.1	94.76	19.0	14,000	LIGHT OIL	319	BBLS	5.79	1,848	54,319	41.15
28	DEBARY	1-10 785	26	0.4	95.97	268.8	13,077	LIGHT OIL	59	BBLS	5.76	340	24,177	92.99
29	HIGGINS	1-4 129	0	0.0	88.79	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14 1,186	662	1.1	89.17	50.9	14,576	LIGHT OIL	1,664	BBLS	5.80	9,649	261,316	39.47
32	RIO PINAR	1 16	0	0.0	97.42	0.0	0	LIGHT OIL	0	BBLS	0.00	0	283	0.00
33	SUWANNEE	1-3 200	83	0.1	96.13	1.3	13,060	LIGHT OIL	187	BBLS	5.80	1,084	25,018	30.14
34	TURNER	1-4 199	0	0.0	94.92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	3,376	0.00
35	OTHER & START UP	-	0	-	0.00	0.0	0	LIGHT OIL	6,592	BBLS	5.80	38,206	862,057	0.00
36	TOTAL		2,695,654									23,483,776	109,697,450	4.07

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-14

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	805	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	22,037	8.7	89.24	39.6	10,958	COAL	9,873	TONS	24.46	241,478	1,198,932	5.44
3	CRYSTAL RIVER	2	500	105,452	31.4	92.15	32.9	10,984	COAL	47,357	TONS	24.46	1,158,325	5,177,740	4.91
4	CRYSTAL RIVER	4	732	371,195	75.5	93.11	78.9	10,427	COAL	164,625	TONS	23.51	3,870,351	12,481,747	3.36
5	CRYSTAL RIVER	5	712	291,673	61.0	95.35	84.1	10,261	COAL	127,302	TONS	23.51	2,992,895	9,790,217	3.36
6	ANCLOTE	1	517	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	94.94	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	95.36	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	95.71	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.79	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	0	0.0	100.00	0.0	0	GAS	0	MCF	0.00	0	1,122,544	0.00
12	ANCLOTE	2	521	64,331	18.4	94.94	18.9	12,517	GAS	805,220	MCF	1.00	805,220	4,626,862	7.19
13	AVON PARK	1-2	69	20	0.0	79.82	29.0	15,850	GAS	317	MCF	1.00	317	19,119	95.60
14	BARTOW	1-4	228	198	0.1	72.77	21.7	13,162	GAS	2,606	MCF	1.00	2,606	28,611	14.45
15	BARTOW CC	1	1279	587,209	68.3	94.18	72.2	7,246	GAS	4,255,013	MCF	1.00	4,255,013	23,180,691	3.95
16	DEBARY	1-10	785	848	0.2	95.93	10.6	12,565	GAS	10,655	MCF	1.00	10,655	219,070	25.83
17	HIGGINS	1-4	129	153	0.2	88.04	19.8	16,124	GAS	2,467	MCF	1.00	2,467	28,007	18.31
18	HINES CC	1-4	2,204	841,035	56.8	95.38	19.7	7,241	GAS	6,089,644	MCF	1.00	6,089,644	33,876,385	4.03
19	INT CITY	1-14	1,186	3,761	0.5	88.65	6.6	12,772	GAS	48,034	MCF	1.00	48,034	554,441	14.74
20	SUWANNEE	1	67	696	1.5	95.36	173.1	13,200	GAS	9,187	MCF	1.00	9,187	111,939	16.08
21	SUWANNEE	2	66	0	0.0	96.43	0.0	0	GAS	0	MCF	0.00	0	28,783	0.00
22	SUWANNEE	3	67	21,924	48.7	96.43	50.3	11,642	GAS	255,247	MCF	1.00	255,247	1,182,793	5.39
23	TIGER BAY CC	1	225	42,463	28.1	88.21	91.2	7,539	GAS	320,112	MCF	1.00	320,112	1,997,574	4.70
24	UNIV OF FLA. CC	1	47	31,910	101.0	98.93	102.1	9,425	GAS	300,763	MCF	1.00	300,763	1,567,969	4.91
25	AVON PARK	1-2	69	0	0.0	79.82	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	0	0.0	72.77	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	231	71	0.0	95.63	30.7	14,423	LIGHT OIL	176	BBLS	5.82	1,024	35,178	49.55
28	DEBARY	1-10	785	64	0.2	95.93	0.0	13,156	LIGHT OIL	145	BBLS	5.81	842	35,522	55.50
29	HIGGINS	1-4	129	0	0.0	88.04	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	297	0.5	88.65	48.9	13,684	LIGHT OIL	700	BBLS	5.81	4,064	135,336	45.57
32	RIO PINAR	1	16	0	0.0	99.64	0.0	0	LIGHT OIL	0	BBLS	0.00	0	283	0.00
33	SUWANNEE	1-3	200	43	0.0	96.07	1.1	13,372	LIGHT OIL	99	BBLS	5.81	575	13,241	30.79
34	TURNER	1-4	199	0	0.0	94.02	0.0	0	LIGHT OIL	0	BBLS	0.00	0	3,376	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	4,898	BBLS	5.80	28,388	639,046	0.00
36	TOTAL			2,385,380									20,397,207	98,055,406	4.11

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-14

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	805	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	52,530	18.8	90.78	45.1	10,833	COAL	23,259	TONS	24.47	569,068	2,627,247	5.00
3	CRYSTAL RIVER	2	500	139,224	37.4	91.99	39.7	10,789	COAL	61,394	TONS	24.47	1,502,125	6,687,360	4.80
4	CRYSTAL RIVER	4	732	418,098	76.8	92.89	80.7	10,412	COAL	185,361	TONS	23.49	4,353,396	13,835,063	3.31
5	CRYSTAL RIVER	5	712	232,265	43.8	92.00	83.9	10,262	COAL	101,482	TONS	23.49	2,383,409	7,850,376	3.38
6	ANCLOTE	1	517	0	0.0	95.67	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	94.85	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	94.84	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	95.81	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	2,246	0.6	95.67	36.2	12,642	GAS	28,393	MCF	1.00	28,393	1,246,196	55.49
12	ANCLOTE	2	521	86,995	22.4	94.85	23.0	11,886	GAS	1,034,002	MCF	1.00	1,034,002	5,625,623	6.47
13	AVON PARK	1-2	69	34	0.1	81.45	49.3	15,441	GAS	525	MCF	1.00	525	20,026	58.90
14	BARTOW	1-4	228	143	0.1	72.58	20.9	13,615	GAS	1,947	MCF	1.00	1,947	25,749	18.01
15	BARTOW CC	1	1279	670,325	70.4	96.65	72.8	7,231	GAS	4,847,337	MCF	1.00	4,847,337	25,773,027	3.84
16	DEBARY	1-10	785	1,607	0.3	95.23	9.9	12,621	GAS	20,282	MCF	1.00	20,282	261,028	16.24
17	HIGGINS	1-4	129	114	0.1	86.53	22.1	15,956	GAS	1,819	MCF	1.00	1,819	25,192	22.10
18	HINES CC	1-4	2,204	761,932	46.5	85.34	17.5	7,285	GAS	5,550,496	MCF	1.00	5,550,496	31,546,657	4.14
19	INT CITY	1-14	1,186	8,472	1.0	88.94	6.3	12,791	GAS	108,366	MCF	1.00	108,366	817,332	9.65
20	SUWANNEE	1	67	1,760	3.5	94.19	238.8	12,995	GAS	22,871	MCF	1.00	22,871	171,562	9.75
21	SUWANNEE	2	66	488	1.0	96.77	28.4	15,061	GAS	7,350	MCF	1.00	7,350	60,792	12.46
22	SUWANNEE	3	67	8,609	17.3	98.39	55.9	11,841	GAS	101,940	MCF	1.00	101,940	515,907	5.99
23	TIGER BAY CC	1	225	70,124	41.9	87.42	93.9	7,447	GAS	522,197	MCF	1.00	522,197	2,878,615	4.11
24	UNIV OF FLA. CC	1	47	23,846	68.2	63.09	102.1	9,425	GAS	224,753	MCF	1.00	224,753	1,237,848	5.19
25	AVON PARK	1-2	69	0	0.0	81.45	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	0	0.0	72.58	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	231	42	0.0	94.92	0.0	14,214	LIGHT OIL	104	BBLS	5.74	597	25,243	60.10
28	DEBARY	1-10	785	29	0.3	95.23	0.0	13,897	LIGHT OIL	70	BBLS	5.76	403	25,540	88.07
29	HIGGINS	1-4	129	0	0.0	86.53	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	310	1.0	88.94	92.6	14,148	LIGHT OIL	756	BBLS	5.80	4,386	142,091	45.84
32	RIO PINAR	1	16	0	0.0	97.10	0.0	0	LIGHT OIL	0	BBLS	0.00	0	283	0.00
33	SUWANNEE	1-3	200	33	0.0	96.45	0.4	13,818	LIGHT OIL	79	BBLS	5.77	456	10,450	31.67
34	TURNER	1-4	199	0	0.0	94.92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	3,376	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	7,676	BBLS	5.80	44,492	996,720	0.00
36	TOTAL			2,479,226									21,330,610	102,409,303	4.13

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-14

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	805	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	71,046	26.2	91.18	50.0	10,906	COAL	31,663	TONS	24.47	774,862	3,530,152	4.97
3	CRYSTAL RIVER	2	500	147,283	40.9	24.13	43.8	10,851	COAL	65,305	TONS	24.47	1,598,160	7,120,533	4.83
4	CRYSTAL RIVER	4	732	395,573	75.1	89.76	80.4	10,568	COAL	178,326	TONS	23.44	4,180,424	12,958,114	3.28
5	CRYSTAL RIVER	5	712	397,244	77.5	96.02	79.4	10,586	COAL	179,384	TONS	23.44	4,205,221	13,031,362	3.28
6	ANCLOTE	1	517	0	0.0	92.73	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	69.95	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	94.67	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	95.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	96.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	54,533	14.6	92.73	39.5	11,763	GAS	641,464	MCF	1.00	641,464	3,971,286	7.28
12	ANCLOTE	2	521	20,928	5.6	69.95	34.9	11,247	GAS	235,374	MCF	1.00	235,374	2,167,840	10.36
13	AVON PARK	1-2	69	169	0.4	83.17	52.5	14,609	GAS	2,469	MCF	1.00	2,469	28,235	16.71
14	BARTOW	1-4	228	462	0.3	72.92	19.3	14,253	GAS	6,585	MCF	1.00	6,585	46,514	10.07
15	BARTOW CC	1	1279	558,181	60.6	96.59	62.5	7,469	GAS	4,169,115	MCF	1.00	4,169,115	23,177,918	4.15
16	DEBARY	1-10	785	5,523	1.0	95.47	9.2	13,059	GAS	72,123	MCF	1.00	72,123	492,998	8.93
17	HIGGINS	1-4	129	634	0.7	87.83	22.3	15,426	GAS	9,780	MCF	1.00	9,780	60,703	9.57
18	HINES CC	1-4	2,204	780,775	49.2	70.09	16.2	7,394	GAS	5,772,995	MCF	1.00	5,772,995	33,012,124	4.23
19	INT CITY	1-14	1,186	22,770	2.8	93.50	5.9	12,906	GAS	293,877	MCF	1.00	293,877	1,650,505	7.25
20	SUWANNEE	1	67	2,959	6.1	95.67	315.5	12,657	GAS	37,453	MCF	1.00	37,453	238,287	8.05
21	SUWANNEE	2	66	719	1.5	97.00	29.4	15,111	GAS	10,865	MCF	1.00	10,865	77,035	10.71
22	SUWANNEE	3	67	25,643	53.2	98.00	55.4	11,906	GAS	305,294	MCF	1.00	305,294	1,427,769	5.57
23	TIGER BAY CC	1	225	102,922	63.5	18.52	98.0	7,161	GAS	737,054	MCF	1.00	737,054	3,877,704	3.77
24	UNIV OF FLA. CC	1	47	29,722	87.8	92.56	102.2	9,431	GAS	280,308	MCF	1.00	280,308	1,503,897	5.06
25	AVON PARK	1-2	69	12	0.4	83.17	0.0	14,833	LIGHT OIL	31	BBLS	5.74	178	4,445	37.04
26	BARTOW	1-4	228	23	0.3	72.92	212.7	13,522	LIGHT OIL	54	BBLS	5.76	311	7,115	30.93
27	BAYBORO	1-4	231	71	0.0	94.67	10.2	13,141	LIGHT OIL	161	BBLS	5.80	933	32,855	46.27
28	DEBARY	1-10	785	274	1.0	95.47	105.5	12,547	LIGHT OIL	592	BBLS	5.81	3,438	93,472	34.11
29	HIGGINS	1-4	129	0	0.0	87.83	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	823	2.8	93.50	104.7	13,818	LIGHT OIL	1,962	BBLS	5.80	11,372	296,853	36.07
32	RIO PINAR	1	16	5	0.0	99.33	0.0	16,600	LIGHT OIL	14	BBLS	5.93	83	2,136	42.72
33	SUWANNEE	1-3	200	189	0.1	96.89	1.1	14,455	LIGHT OIL	472	BBLS	5.79	2,732	62,268	32.95
34	TURNER	1-4	199	76	0.1	95.17	19.1	14,197	LIGHT OIL	185	BBLS	5.83	1,079	27,588	36.30
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	7,415	BBLS	5.80	42,981	957,424	0.00
36	TOTAL			2,618,559									23,396,530	109,857,132	4.20

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: May-14

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	0	0.0	0.00	0.0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	127,723	45.8	88.91	50.8	10,894	COAL	57,021	TONS	24.40	1,391,461	6,079,369	4.76
3	CRYSTAL RIVER	2	494	170,668	46.4	91.07	49.6	10,759	COAL	75,244	TONS	24.40	1,836,137	7,973,927	4.67
4	CRYSTAL RIVER	4	722	397,065	73.9	42.91	76.4	10,655	COAL	180,925	TONS	23.38	4,230,878	12,843,753	3.23
5	CRYSTAL RIVER	5	700	375,174	72.0	94.22	75.2	10,823	COAL	173,645	TONS	23.38	4,060,634	12,351,476	3.29
6	ANCLOTE	1	501	0	0.0	91.99	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	44.46	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	94.84	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	92.58	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	92.90	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	105,953	28.4	91.99	38.1	11,702	GAS	1,239,908	MCF	1.00	1,239,908	6,491,346	6.13
12	ANCLOTE	2	510	3,971	1.0	44.46	35.4	12,432	GAS	49,368	MCF	1.00	49,368	1,336,308	33.65
13	AVON PARK	1-2	49	670	2.0	79.84	51.2	16,360	GAS	10,961	MCF	1.00	10,961	64,731	9.66
14	BARTOW	1-4	177	1,809	1.6	73.47	23.9	14,329	GAS	25,922	MCF	1.00	25,922	129,512	7.16
15	BARTOW CC	1	1159	743,880	86.3	44.44	89.1	7,285	GAS	5,419,081	MCF	1.00	5,419,081	28,127,497	3.78
16	DEBARY	1-10	645	19,509	4.8	95.61	11.0	13,341	GAS	260,272	MCF	1.00	260,272	1,299,678	6.66
17	HIGGINS	1-4	113	3,319	3.9	87.90	21.9	16,267	GAS	53,990	MCF	1.00	53,990	251,047	7.56
18	HINES CC	1-4	1,912	979,364	68.8	59.69	19.8	7,299	GAS	7,148,139	MCF	1.00	7,148,139	38,325,694	3.91
19	INT CITY	1-14	987	63,186	9.5	95.35	6.9	13,110	GAS	828,355	MCF	1.00	828,355	3,932,175	6.22
20	SUWANNEE	1	52	7,032	18.2	97.42	65.6	13,890	GAS	97,672	MCF	1.00	97,672	494,877	7.04
21	SUWANNEE	2	50	5,612	15.1	98.06	38.3	14,539	GAS	81,594	MCF	1.00	81,594	382,085	6.81
22	SUWANNEE	3	51	26,736	70.5	99.03	75.9	12,010	GAS	321,098	MCF	1.00	321,098	1,462,312	5.47
23	TIGER BAY CC	1	204	75,872	50.0	2.12	90.9	7,381	GAS	560,019	MCF	1.00	560,019	3,029,329	3.99
24	UNIV OF FLA. CC	1	46	32,616	95.3	97.42	97.8	9,430	GAS	307,563	MCF	1.00	307,563	1,590,796	4.88
25	AVON PARK	1-2	49	58	2.0	79.84	371.4	18,741	LIGHT OIL	188	BBLS	5.78	1,087	24,621	42.45
26	BARTOW	1-4	177	261	1.6	73.47	116.9	16,582	LIGHT OIL	747	BBLS	5.79	4,328	98,544	37.76
27	BAYBORO	1-4	174	1,571	1.2	95.24	17.4	14,790	LIGHT OIL	4,009	BBLS	5.80	23,235	540,547	34.41
28	DEBARY	1-10	645	3,551	4.8	95.61	31.9	14,590	LIGHT OIL	8,939	BBLS	5.80	51,810	1,171,257	32.98
29	HIGGINS	1-4	113	0	0.0	87.90	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	6,325	9.5	95.35	42.7	14,481	LIGHT OIL	15,804	BBLS	5.80	91,591	2,070,207	32.73
32	RIO PINAR	1	12	46	0.5	99.68	76.7	18,587	LIGHT OIL	148	BBLS	5.78	855	19,279	41.91
33	SUWANNEE	1-3	153	1,137	1.0	98.17	4.8	14,124	LIGHT OIL	2,771	BBLS	5.80	16,059	364,251	32.04
34	TURNER	1-4	149	507	0.5	94.03	20.0	17,535	LIGHT OIL	1,535	BBLS	5.79	8,890	201,897	39.82
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	6,765	BBLS	5.80	39,212	869,174	0.00
36	TOTAL			3,153,615									28,160,119	131,525,689	4.17

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-14

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC 3	789	0	0.0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER 1	375	110,126	40.8	90.21	54.5	10,830	COAL	48,974 TONS	24.35	1,192,614	5,145,078	4.67
3	CRYSTAL RIVER 2	494	174,867	49.2	91.67	52.1	10,710	COAL	76,908 TONS	24.35	1,872,851	7,993,575	4.57
4	CRYSTAL RIVER 4	722	413,944	79.6	80.53	82.4	10,578	COAL	187,624 TONS	23.34	4,378,741	13,052,708	3.15
5	CRYSTAL RIVER 5	700	385,529	76.5	92.56	80.3	10,758	COAL	177,715 TONS	23.34	4,147,473	12,395,519	3.22
6	ANCLOTE 1	501	0	0.0	93.91	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE 2	510	0	0.0	92.98	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE 1	30	0	0.0	94.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE 2	30	0	0.0	92.67	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE 3	71	0	0.0	95.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE 1	501	70,150	19.4	93.91	42.0	11,659	GAS	817,886 MCF	1.00	817,886	4,656,630	6.64
12	ANCLOTE 2	510	135,103	36.8	92.98	38.4	11,089	GAS	1,498,130 MCF	1.00	1,498,130	7,595,964	5.62
13	AVON PARK 1-2	49	191	0.6	82.50	44.7	16,550	GAS	3,161 MCF	1.00	3,161	30,929	16.19
14	BARTOW 1-4	177	899	0.7	82.42	19.8	14,542	GAS	13,073 MCF	1.00	13,073	73,758	8.20
15	BARTOW CC 1	1159	733,857	87.9	61.29	89.4	7,237	GAS	5,311,120 MCF	1.00	5,311,120	27,612,226	3.76
16	DEBARY 1-10	645	8,656	2.0	95.70	10.6	13,122	GAS	113,586 MCF	1.00	113,586	663,505	7.67
17	HIGGINS 1-4	113	1,165	1.4	88.83	21.0	16,591	GAS	19,329 MCF	1.00	19,329	100,790	8.65
18	HINES CC 1-4	1,912	1,138,568	82.7	80.65	21.8	7,240	GAS	8,243,736 MCF	1.00	8,243,736	42,995,435	3.78
19	INT CITY 1-14	987	33,064	4.9	91.50	7.1	12,946	GAS	428,041 MCF	1.00	428,041	2,201,254	6.66
20	SUWANNEE 1	52	5,141	13.7	93.67	117.7	13,777	GAS	70,830 MCF	1.00	70,830	378,014	7.35
21	SUWANNEE 2	50	2,038	5.7	96.00	38.1	14,794	GAS	30,151 MCF	1.00	30,151	159,066	7.81
22	SUWANNEE 3	51	26,140	71.2	98.33	74.9	12,063	GAS	315,338 MCF	1.00	315,338	1,434,533	5.49
23	TIGER BAY CC 1	204	75,003	51.1	88.19	95.7	7,307	GAS	548,075 MCF	1.00	548,075	2,972,679	3.96
24	UNIV OF FLA. CC 1	46	31,968	96.5	98.67	97.9	9,427	GAS	301,360 MCF	1.00	301,360	1,561,225	4.88
25	AVON PARK 1-2	49	6	0.6	82.50	0.0	19,667	LIGHT OIL	20 BBLS	5.90	118	3,084	51.40
26	BARTOW 1-4	177	13	0.7	82.42	0.0	17,385	LIGHT OIL	39 BBLS	5.79	226	5,130	39.46
27	BAYBORO 1-4	174	526	0.4	94.50	16.8	15,067	LIGHT OIL	1,368 BBLS	5.79	7,925	191,390	36.39
28	DEBARY 1-10	645	410	2.0	95.70	100.4	14,849	LIGHT OIL	1,050 BBLS	5.80	6,088	151,724	37.01
29	HIGGINS 1-4	113	0	0.0	88.83	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY 1-14	987	1,888	4.9	91.50	56.2	15,357	LIGHT OIL	5,002 BBLS	5.80	28,994	677,086	35.86
32	RIO PINAR 1	12	0	0.0	98.67	0.0	0	LIGHT OIL	0 BBLS	0.00	0	283	0.00
33	SUWANNEE 1-3	153	477	0.4	96.00	2.0	14,816	LIGHT OIL	1,219 BBLS	5.80	7,067	159,792	33.50
34	TURNER 1-4	149	45	0.0	95.25	15.1	17,800	LIGHT OIL	138 BBLS	5.80	801	21,205	47.12
35	OTHER & START UP	-	0	-	0.00	0.0	0	LIGHT OIL	6,732 BBLS	5.80	39,025	862,250	0.00
36	TOTAL		3,349,774								29,395,739	133,094,832	3.97

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-14

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	0	0	0.00	0	0 NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	134,167	48.1	92.57	51.9	10,874 COAL	60,041 TONS	24.30	1,458,870	6,168,535	4.60
3	CRYSTAL RIVER	2	494	174,577	47.5	92.61	49.8	10,753 COAL	77,257 TONS	24.30	1,877,180	7,893,977	4.52
4	CRYSTAL RIVER	4	722	412,971	76.9	94.75	79.2	10,613 COAL	188,098 TONS	23.30	4,383,011	12,916,471	3.13
5	CRYSTAL RIVER	5	700	386,464	74.2	93.56	77.4	10,789 COAL	178,939 TONS	23.30	4,169,582	12,317,199	3.19
6	ANCLOTE	1	501	0	0.0	93.42	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	95.20	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	30.00	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	91.94	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	93.87	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	91,854	24.6	93.42	37.4	11,835 GAS	1,087,105 MCF	1.00	1,087,105	5,846,016	6.36
12	ANCLOTE	2	510	136,609	36.0	95.20	37.2	11,161 GAS	1,524,648 MCF	1.00	1,524,648	7,747,140	5.67
13	AVON PARK	1-2	49	290	0.9	81.77	49.6	16,634 GAS	4,824 MCF	1.00	4,824	38,230	13.18
14	BARTOW	1-4	177	1,322	1.1	97.34	20.6	14,538 GAS	19,219 MCF	1.00	19,219	100,777	7.62
15	BARTOW CC	1	1,159	753,216	87.4	97.10	89.4	7,253 GAS	5,463,132 MCF	1.00	5,463,132	28,400,185	3.77
16	DEBARY	1-10	645	10,772	2.4	94.94	10.9	13,118 GAS	141,311 MCF	1.00	141,311	786,695	7.30
17	HIGGINS	1-4	113	1,588	1.9	88.79	21.0	16,620 GAS	26,392 MCF	1.00	26,392	131,944	8.31
18	HINES CC	1-4	1,912	1,165,299	81.9	95.51	21.7	7,228 GAS	8,422,224 MCF	1.00	8,422,224	43,968,816	3.77
19	INT CITY	1-14	987	37,818	5.6	96.31	7.3	12,926 GAS	488,838 MCF	1.00	488,838	2,475,688	6.55
20	SUWANNEE	1	52	5,468	14.1	94.52	98.3	13,760 GAS	75,238 MCF	1.00	75,238	398,867	7.29
21	SUWANNEE	2	50	2,660	7.2	97.42	38.0	14,768 GAS	39,283 MCF	1.00	39,283	199,468	7.50
22	SUWANNEE	3	51	26,697	70.4	99.35	75.0	12,063 GAS	322,056 MCF	1.00	322,056	1,471,291	5.51
23	TIGER BAY CC	1	204	108,711	71.6	89.68	96.0	7,272 GAS	790,503 MCF	1.00	790,503	4,039,182	3.72
24	UNIV OF FLA. CC	1	46	33,048	96.6	98.71	97.9	9,427 GAS	311,559 MCF	1.00	311,559	1,612,773	4.88
25	AVON PARK	1-2	49	26	0.9	81.77	322.4	18,692 LIGHT OIL	84 BBLS	5.79	486	11,196	43.06
26	BARTOW	1-4	177	62	1.1	97.34	260.6	18,032 LIGHT OIL	193 BBLS	5.79	1,118	25,290	40.79
27	BAYBORO	1-4	174	1,023	0.8	95.65	17.3	15,013 LIGHT OIL	2,650 BBLS	5.80	15,358	358,922	35.09
28	DEBARY	1-10	645	881	2.4	94.94	58.3	15,053 LIGHT OIL	2,289 BBLS	5.79	13,262	310,096	35.20
29	HIGGINS	1-4	113	0	0.0	88.79	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	3,337	5.6	96.31	37.9	15,364 LIGHT OIL	8,847 BBLS	5.80	51,270	1,164,346	34.89
32	RIO PINAR	1	12	8	0.1	98.71	66.7	18,625 LIGHT OIL	26 BBLS	5.73	149	3,571	44.64
33	SUWANNEE	1-3	153	819	0.7	97.10	3.3	14,891 LIGHT OIL	2,104 BBLS	5.80	12,196	274,825	33.56
34	TURNER	1-4	149	146	0.1	93.23	16.3	17,815 LIGHT OIL	450 BBLS	5.78	2,601	61,072	41.83
35	OTHER & START UP		-	0	-	0.00	0.0	0 LIGHT OIL	6,788 BBLS	5.80	39,341	866,219	0.00
36	TOTAL			3,489,833							30,740,756	139,588,791	4.00

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-14

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	0	0	0.00	0	0 NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	138,289	49.6	87.97	52.8	10,859 COAL	61,905 TONS	24.26	1,501,709	6,277,365	4.54
3	CRYSTAL RIVER	2	494	178,939	48.7	93.53	50.7	10,744 COAL	79,251 TONS	24.26	1,922,496	7,994,006	4.47
4	CRYSTAL RIVER	4	722	422,004	78.6	93.34	81.7	10,574 COAL	191,740 TONS	23.27	4,462,358	13,094,175	3.10
5	CRYSTAL RIVER	5	700	394,468	75.7	93.24	79.0	10,761 COAL	182,397 TONS	23.27	4,244,912	12,485,821	3.17
6	ANCLOTE	1	501	0	0.0	92.35	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	96.01	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	95.48	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	32.26	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	91.29	0.0	0 HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	128,404	34.4	92.35	35.7	11,804 GAS	1,515,641 MCF	1.00	1,515,641	7,714,067	6.01
12	ANCLOTE	2	510	140,415	37.0	96.01	39.4	11,053 GAS	1,552,029 MCF	1.00	1,552,029	7,872,318	5.61
13	AVON PARK	1-2	49	296	0.9	80.48	51.3	16,564 GAS	4,903 MCF	1.00	4,903	38,593	13.04
14	BARTOW	1-4	177	1,458	1.2	97.58	21.8	14,543 GAS	21,203 MCF	1.00	21,203	109,482	7.51
15	BARTOW CC	1	1,159	743,585	86.2	47.06	90.0	7,271 GAS	5,406,798 MCF	1.00	5,406,798	28,177,041	3.79
16	DEBARY	1-10	645	13,063	3.0	88.35	11.1	13,140 GAS	171,646 MCF	1.00	171,646	919,188	7.04
17	HIGGINS	1-4	113	2,182	2.6	87.82	21.5	16,501 GAS	36,005 MCF	1.00	36,005	173,856	7.97
18	HINES CC	1-4	1,912	1,172,921	82.5	93.77	21.7	7,220 GAS	8,469,021 MCF	1.00	8,469,021	44,206,025	3.77
19	INT CITY	1-14	987	48,391	7.0	96.59	7.0	12,971 GAS	627,660 MCF	1.00	627,660	3,081,381	6.37
20	SUWANNEE	1	52	5,715	14.8	93.55	82.0	13,792 GAS	78,824 MCF	1.00	78,824	414,764	7.26
21	SUWANNEE	2	50	3,117	8.4	95.16	38.2	14,773 GAS	46,048 MCF	1.00	46,048	229,046	7.35
22	SUWANNEE	3	51	26,580	70.1	98.06	74.1	12,035 GAS	319,882 MCF	1.00	319,882	1,463,125	5.50
23	TIGER BAY CC	1	204	129,674	85.4	90.65	97.2	7,234 GAS	938,045 MCF	1.00	938,045	4,684,005	3.61
24	UNIV OF FLA. CC	1	46	33,048	96.6	98.71	97.9	9,428 GAS	311,578 MCF	1.00	311,578	1,614,101	4.88
25	AVON PARK	1-2	49	31	0.9	80.48	333.7	18,387 LIGHT OIL	98 BBLS	5.82	570	13,034	42.05
26	BARTOW	1-4	177	126	1.2	97.58	223.7	15,317 LIGHT OIL	333 BBLS	5.80	1,930	43,603	34.61
27	BAYBORO	1-4	174	1,008	0.8	95.48	18.7	14,748 LIGHT OIL	2,564 BBLS	5.80	14,866	347,363	34.46
28	DEBARY	1-10	645	1,307	3.0	88.35	57.1	14,229 LIGHT OIL	3,208 BBLS	5.80	18,597	427,680	32.72
29	HIGGINS	1-4	113	0	0.0	87.82	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0 LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	3,223	7.0	96.59	50.3	15,241 LIGHT OIL	8,476 BBLS	5.80	49,121	1,115,701	34.62
32	RIO PINAR	1	12	25	0.3	98.71	69.4	18,600 LIGHT OIL	80 BBLS	5.81	465	10,532	42.13
33	SUWANNEE	1-3	153	847	0.7	95.59	3.8	14,570 LIGHT OIL	2,129 BBLS	5.80	12,341	277,734	32.79
34	TURNER	1-4	149	297	0.3	95.65	19.9	17,458 LIGHT OIL	894 BBLS	5.80	5,185	118,243	39.81
35	OTHER & START UP		-	0	-	0.00	0.0	0 LIGHT OIL	6,091 BBLS	5.80	35,302	776,247	0.00
36	TOTAL			3,589,413							31,769,135	143,678,496	4.00

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-14

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC 3	789	0	0	0.00	0	0	NUCLEAR	0 MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER 1	375	124,245	46.0	26.77	49.8	10,910	COAL	55,905 TONS	24.25	1,355,555	5,685,371	4.58
3	CRYSTAL RIVER 2	494	164,712	46.3	92.97	47.9	10,781	COAL	73,237 TONS	24.25	1,775,808	7,401,153	4.49
4	CRYSTAL RIVER 4	722	411,262	79.1	93.65	82.4	10,568	COAL	186,916 TONS	23.25	4,346,283	12,741,004	3.10
5	CRYSTAL RIVER 5	700	384,519	76.3	93.63	79.5	10,757	COAL	177,883 TONS	23.25	4,136,245	12,154,750	3.16
6	ANCLOTE 1	501	0	0.0	55.21	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
7	ANCLOTE 2	510	0	0.0	93.65	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
8	SUWANNEE 1	30	0	0.0	93.33	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
9	SUWANNEE 2	30	0	0.0	95.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
10	SUWANNEE 3	71	0	0.0	30.00	0.0	0	HEAVY OIL	0 BBLS	0.00	0	0	0.00
11	ANCLOTE 1	501	114,914	31.9	55.21	33.4	11,976	GAS	1,376,214 MCF	1.00	1,376,214	7,129,718	6.20
12	ANCLOTE 2	510	114,611	31.2	93.65	36.8	11,230	GAS	1,287,035 MCF	1.00	1,287,035	6,740,452	5.88
13	AVON PARK 1-2	49	46	0.2	81.83	69.4	16,543	GAS	761 MCF	1.00	761	20,592	44.77
14	BARTOW 1-4	177	507	0.5	97.83	23.6	14,558	GAS	7,381 MCF	1.00	7,381	49,488	9.76
15	BARTOW CC 1	1,159	727,849	87.2	80.89	89.0	7,230	GAS	5,262,091 MCF	1.00	5,262,091	27,631,903	3.80
16	DEBARY 1-10	645	5,609	1.3	95.47	10.8	13,179	GAS	73,922 MCF	1.00	73,922	495,368	8.83
17	HIGGINS 1-4	113	417	0.5	88.00	23.1	16,206	GAS	6,758 MCF	1.00	6,758	46,769	11.22
18	HINES CC 1-4	1,912	1,051,909	76.4	60.73	20.6	7,269	GAS	7,646,447 MCF	1.00	7,646,447	40,750,993	3.87
19	INT CITY 1-14	987	23,049	3.4	95.43	6.9	13,024	GAS	300,200 MCF	1.00	300,200	1,662,061	7.21
20	SUWANNEE 1	52	3,727	10.0	93.33	170.7	13,696	GAS	51,046 MCF	1.00	51,046	294,774	7.91
21	SUWANNEE 2	50	1,081	3.0	96.67	38.6	14,985	GAS	16,199 MCF	1.00	16,199	99,492	9.20
22	SUWANNEE 3	51	25,267	68.8	98.33	73.7	12,071	GAS	304,998 MCF	1.00	304,998	1,403,274	5.55
23	TIGER BAY CC 1	204	115,377	78.6	91.00	97.2	7,227	GAS	833,814 MCF	1.00	833,814	4,244,045	3.68
24	UNIV OF FLA. CC 1	46	20,196	61.0	61.75	97.8	9,428	GAS	190,407 MCF	1.00	190,407	1,090,175	5.40
25	AVON PARK 1-2	49	22	0.2	81.83	138.8	17,864	LIGHT OIL	68 BBLS	5.78	393	9,116	41.44
26	BARTOW 1-4	177	77	0.5	97.83	165.0	14,831	LIGHT OIL	197 BBLS	5.80	1,142	25,752	33.44
27	BAYBORO 1-4	174	333	0.3	96.08	19.1	14,411	LIGHT OIL	827 BBLS	5.80	4,799	119,726	35.95
28	DEBARY 1-10	645	524	1.3	95.47	67.9	13,510	LIGHT OIL	1,222 BBLS	5.79	7,079	172,697	32.96
29	HIGGINS 1-4	113	0	0.0	88.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
31	INT CITY 1-14	987	1,142	3.4	95.43	68.1	15,124	LIGHT OIL	2,980 BBLS	5.80	17,272	416,049	36.43
32	RIO PINAR 1	12	13	0.2	98.00	108.3	18,615	LIGHT OIL	42 BBLS	5.76	242	5,606	43.12
33	SUWANNEE 1-3	153	291	0.3	96.11	1.5	14,488	LIGHT OIL	727 BBLS	5.80	4,216	94,704	32.54
34	TURNER 1-4	149	124	0.1	95.17	20.8	16,597	LIGHT OIL	354 BBLS	5.81	2,058	48,882	39.42
35	OTHER & START UP	-	0	-	0.00	0.0	0	LIGHT OIL	5,209 BBLS	5.80	30,193	662,657	0.00
36	TOTAL		3,291,823								29,038,558	131,196,571	3.99

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-14

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	0	0	0.00	0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	375	84,765	30.4	91.04	52.4	10,863	COAL	37,917	TONS	24.28	920,783	3,976,335	4.69
3	CRYSTAL RIVER	2	494	47,688	13.0	91.29	43.3	10,870	COAL	21,347	TONS	24.28	518,382	2,304,585	4.83
4	CRYSTAL RIVER	4	722	399,134	74.3	92.38	78.1	10,622	COAL	182,562	TONS	23.22	4,239,757	12,458,460	3.12
5	CRYSTAL RIVER	5	700	377,915	72.6	93.45	75.0	10,816	COAL	176,006	TONS	23.22	4,087,505	12,032,966	3.18
6	ANCLOTE	1	501	0	0.0	63.41	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	510	0	0.0	95.45	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	96.13	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.10	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	71	0	0.0	95.81	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	501	116,275	31.2	63.41	32.8	12,036	GAS	1,399,456	MCF	1.00	1,399,456	7,336,129	6.31
12	ANCLOTE	2	510	76,059	20.0	95.45	41.0	11,085	GAS	843,111	MCF	1.00	843,111	4,865,957	6.40
13	AVON PARK	1-2	49	235	0.7	82.42	47.7	16,643	GAS	3,911	MCF	1.00	3,911	34,635	14.74
14	BARTOW	1-4	177	968	0.8	97.50	20.5	14,541	GAS	14,076	MCF	1.00	14,076	79,767	8.24
15	BARTOW CC	1	1,159	724,494	84.0	95.80	87.4	7,266	GAS	5,264,098	MCF	1.00	5,264,098	28,035,471	3.87
16	DEBARY	1-10	645	9,982	2.2	96.19	10.4	13,213	GAS	131,890	MCF	1.00	131,890	758,290	7.60
17	HIGGINS	1-4	113	1,534	1.8	88.95	21.2	16,494	GAS	25,302	MCF	1.00	25,302	129,611	8.45
18	HINES CC	1-4	1,912	796,467	56.0	76.88	20.8	7,340	GAS	5,846,383	MCF	1.00	5,846,383	33,332,193	4.19
19	INT CITY	1-14	987	33,900	4.9	88.18	6.9	12,999	GAS	440,653	MCF	1.00	440,653	2,301,897	6.79
20	SUWANNEE	1	52	5,851	15.1	93.87	66.6	13,882	GAS	81,226	MCF	1.00	81,226	432,601	7.39
21	SUWANNEE	2	50	3,800	10.2	97.10	38.2	14,438	GAS	54,863	MCF	1.00	54,863	272,375	7.17
22	SUWANNEE	3	51	26,336	69.4	99.35	72.4	12,009	GAS	316,261	MCF	1.00	316,261	1,476,157	5.61
23	TIGER BAY CC	1	204	17,413	11.5	64.65	94.8	7,373	GAS	128,379	MCF	1.00	128,379	1,174,450	6.74
24	UNIV OF FLA. CC	1	46	29,592	86.5	88.18	97.8	9,435	GAS	279,194	MCF	1.00	279,194	1,498,670	5.06
25	AVON PARK	1-2	49	22	0.7	82.42	524.5	18,227	LIGHT OIL	69	BBLS	5.81	401	9,243	42.01
26	BARTOW	1-4	177	46	0.8	97.50	286.4	15,543	LIGHT OIL	123	BBLS	5.81	715	16,036	34.86
27	BAYBORO	1-4	174	578	0.4	95.08	18.5	14,716	LIGHT OIL	1,467	BBLS	5.80	8,506	202,282	35.00
28	DEBARY	1-10	645	732	2.2	96.19	79.1	14,333	LIGHT OIL	1,811	BBLS	5.79	10,492	246,742	33.71
29	HIGGINS	1-4	113	0	0.0	88.95	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	987	2,294	4.9	88.18	58.2	14,583	LIGHT OIL	5,772	BBLS	5.80	33,453	772,669	33.68
32	RIO PINAR	1	12	8	0.1	97.42	66.7	18,625	LIGHT OIL	26	BBLS	5.73	149	3,542	44.28
33	SUWANNEE	1-3	153	467	0.4	96.77	2.6	14,373	LIGHT OIL	1,158	BBLS	5.80	6,712	149,953	32.11
34	TURNER	1-4	149	150	0.1	94.44	20.1	17,160	LIGHT OIL	445	BBLS	5.78	2,574	59,976	39.98
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	6,438	BBLS	5.80	37,315	814,407	0.00
36	TOTAL			2,756,705									24,695,547	114,775,399	4.16

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-14

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3 805	0	0	0.00	0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1 376	41,041	15.2	88.59	43.7	10,860	COAL	18,343	TONS	24.30	445,724	2,020,286	4.92
3	CRYSTAL RIVER	2 500	136,872	38.0	92.89	39.2	10,796	COAL	60,811	TONS	24.30	1,477,643	6,347,973	4.64
4	CRYSTAL RIVER	4 732	193,871	36.8	93.71	77.2	10,445	COAL	87,233	TONS	23.21	2,025,027	6,295,489	3.25
5	CRYSTAL RIVER	5 712	407,247	79.4	92.89	83.6	10,273	COAL	180,217	TONS	23.21	4,183,549	12,356,060	3.03
6	ANCLOTE	1 517	0	0.0	90.91	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2 521	0	0.0	95.30	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1 30	0	0.0	95.33	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2 30	0	0.0	94.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3 73	0	0.0	95.00	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1 517	85,284	22.9	90.91	26.4	12,588	GAS	1,073,524	MCF	1.00	1,073,524	5,673,213	6.65
12	ANCLOTE	2 521	32,482	8.7	95.30	137.3	11,567	GAS	375,726	MCF	1.00	375,726	2,715,247	8.36
13	AVON PARK	1-2 69	12	0.0	82.00	0.0	16,167	GAS	194	MCF	1.00	194	18,562	154.68
14	BARTOW	1-4 228	47	0.0	97.17	607.0	14,021	GAS	659	MCF	1.00	659	20,063	42.69
15	BARTOW CC	1 1,279	590,559	64.1	94.52	67.5	7,247	GAS	4,280,046	MCF	1.00	4,280,046	22,805,993	3.86
16	DEBARY	1-10 785	370	0.1	95.20	296.9	12,924	GAS	4,782	MCF	1.00	4,782	192,969	52.15
17	HIGGINS	1-4 129	84	0.1	88.08	410.3	15,976	GAS	1,342	MCF	1.00	1,342	22,958	27.33
18	HINES CC	1-4 2,204	824,742	52.0	97.30	26.9	7,344	GAS	6,057,043	MCF	1.00	6,057,043	33,050,059	4.01
19	INT CITY	1-14 1,186	3,608	0.4	93.02	69.4	12,841	GAS	46,332	MCF	1.00	46,332	541,801	15.02
20	SUWANNEE	1 67	1,262	2.6	96.00	376.7	12,858	GAS	16,227	MCF	1.00	16,227	140,744	11.15
21	SUWANNEE	2 66	213	0.4	96.33	29.3	15,183	GAS	3,234	MCF	1.00	3,234	42,492	19.95
22	SUWANNEE	3 67	23,413	48.5	99.67	51.1	11,672	GAS	273,273	MCF	1.00	273,273	1,230,362	5.26
23	TIGER BAY CC	1 225	8,379	5.2	85.00	95.5	7,666	GAS	64,236	MCF	1.00	64,236	876,743	10.46
24	UNIV OF FLA. CC	1 47	33,754	99.7	97.67	100.0	9,426	GAS	318,170	MCF	1.00	318,170	1,607,771	4.76
25	AVON PARK	1-2 69	0	0.0	82.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4 228	0	0.0	97.17	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4 231	0	0.0	95.58	0.0	0	LIGHT OIL	0	BBLS	0.00	0	11,508	0.00
28	DEBARY	1-10 785	40	0.1	95.20	0.0	19,525	LIGHT OIL	134	BBLS	5.83	781	33,514	83.79
29	HIGGINS	1-4 129	0	0.0	88.08	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER	0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14 1,186	55	0.4	93.02	0.0	14,982	LIGHT OIL	141	BBLS	5.84	824	61,883	112.51
32	RIO PINAR	1 16	0	0.0	97.67	0.0	0	LIGHT OIL	0	BBLS	0.00	0	283	0.00
33	SUWANNEE	1-3 200	12	0.0	97.33	0.2	13,583	LIGHT OIL	28	BBLS	5.82	163	3,623	30.19
34	TURNER	1-4 199	0	0.0	93.92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	3,376	0.00
35	OTHER & START UP	0	0	-	0.00	0.0	0	LIGHT OIL	5,838	BBLS	5.80	33,836	734,633	0.00
36	TOTAL		2,383,347									20,682,335	96,807,605	4.06

Docket No. 130001-EI
Schedule E4
Exhibit TGF-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-14

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	805	0	0	0.00	0	0	NUCLEAR	0	MMBTU	0.00	0	0	0.00
2	CRYSTAL RIVER	1	376	10,960	3.9	90.08	51.1	10,723	COAL	4,831	TONS	24.33	117,529	650,145	5.93
3	CRYSTAL RIVER	2	500	122,045	32.8	90.92	34.8	10,915	COAL	54,758	TONS	24.33	1,332,107	5,808,472	4.76
4	CRYSTAL RIVER	4	732	344,411	63.2	92.83	78.7	10,430	COAL	154,869	TONS	23.20	3,592,276	10,702,284	3.11
5	CRYSTAL RIVER	5	712	431,862	81.5	93.24	84.8	10,262	COAL	191,065	TONS	23.20	4,431,862	13,061,110	3.02
6	ANCLOTE	1	517	0	0.0	93.81	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
7	ANCLOTE	2	521	0	0.0	94.65	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
8	SUWANNEE	1	30	0	0.0	94.52	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
9	SUWANNEE	2	30	0	0.0	96.45	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
10	SUWANNEE	3	73	0	0.0	93.87	0.0	0	HEAVY OIL	0	BBLS	0.00	0	0	0.00
11	ANCLOTE	1	517	72,595	18.9	93.81	19.6	13,375	GAS	970,938	MCF	1.00	970,938	5,332,531	7.35
12	ANCLOTE	2	521	16,585	4.3	94.65	31.2	11,592	GAS	192,254	MCF	1.00	192,254	1,956,158	11.79
13	AVON PARK	1-2	69	0	0.0	77.26	0.0	0	GAS	0	MCF	0.00	0	17,740	0.00
14	BARTOW	1-4	228	52	0.0	95.89	22.8	13,962	GAS	726	MCF	1.00	726	20,418	39.27
15	BARTOW CC	1	1279	661,294	69.5	97.03	71.3	7,218	GAS	4,773,473	MCF	1.00	4,773,473	25,360,653	3.84
16	DEBARY	1-10	785	449	0.1	95.71	9.5	12,590	GAS	5,653	MCF	1.00	5,653	197,211	43.92
17	HIGGINS	1-4	129	18	0.0	87.10	14.0	15,222	GAS	274	MCF	1.00	274	18,457	102.54
18	HINES CC	1-4	2,204	879,058	53.6	94.53	19.3	7,270	GAS	6,390,836	MCF	1.00	6,390,836	35,084,916	3.99
19	INT CITY	1-14	1,186	2,218	0.3	89.00	6.3	12,821	GAS	28,437	MCF	1.00	28,437	468,700	21.13
20	SUWANNEE	1	67	1,069	2.1	95.48	265.9	13,134	GAS	14,040	MCF	1.00	14,040	132,836	12.43
21	SUWANNEE	2	66	230	0.5	97.74	29.0	15,104	GAS	3,474	MCF	1.00	3,474	43,846	19.06
22	SUWANNEE	3	67	23,723	47.6	98.39	50.7	11,672	GAS	276,900	MCF	1.00	276,900	1,272,597	5.36
23	TIGER BAY CC	1	225	37,302	22.3	87.79	94.2	7,507	GAS	280,013	MCF	1.00	280,013	1,818,583	4.88
24	UNIV OF FLA. CC	1	47	35,136	100.5	98.39	102.1	9,426	GAS	331,178	MCF	1.00	331,178	1,695,036	4.82
25	AVON PARK	1-2	69	0	0.0	77.26	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
26	BARTOW	1-4	228	0	0.0	95.89	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	BAYBORO	1-4	231	0	0.0	95.56	0.0	0	LIGHT OIL	0	BBLS	0.00	0	11,508	0.00
28	DEBARY	1-10	785	0	0.0	95.71	0.0	0	LIGHT OIL	0	BBLS	0.00	0	16,464	0.00
29	HIGGINS	1-4	129	0	0.0	87.10	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
31	INT CITY	1-14	1,186	38	0.3	89.00	190.2	15,289	LIGHT OIL	100	BBLS	5.81	581	56,556	148.83
32	RIO PINAR	1	16	0	0.0	97.74	0.0	0	LIGHT OIL	0	BBLS	0.00	0	283	0.00
33	SUWANNEE	1-3	200	4	0.0	97.20	0.1	15,000	LIGHT OIL	10	BBLS	6.00	60	1,327	33.18
34	TURNER	1-4	199	0	0.0	94.11	0.0	0	LIGHT OIL	0	BBLS	0.00	0	3,376	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	7,080	BBLS	5.80	41,036	886,493	0.00
36	TOTAL			2,639,049									22,783,647	104,617,700	3.96

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2014

	HEAVY OIL		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Subtotal
1	PURCHASES:								
2	UNITS	BBL	0	0	0	0	0	0	0
3	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	AMOUNT	$	0	0	0	0	0	0	0
5	BURNED:								
6	UNITS	BBL	0	0	0	0	0	0	0
7	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	AMOUNT	$	0	0	0	0	0	0	0
9	ENDING INVENTORY:								
10	UNITS	BBL	0	0	0	0	0	0	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	8,821	6,018	8,685	10,886	40,906	15,568	90,884
15	UNIT COST	$/BBL	139.50	143.24	138.60	136.33	131.03	133.09	134.37
16	AMOUNT	$	1,230,546	861,982	1,203,703	1,484,156	5,359,777	2,071,944	12,212,110
17	BURNED:								
18	UNITS	BBL	8,821	6,018	8,685	10,886	40,906	15,568	90,884
19	UNIT COST	$/BBL	139.50	143.24	138.60	136.33	131.03	133.09	134.37
20	AMOUNT	$	1,230,546	861,982	1,203,703	1,484,156	5,359,777	2,071,944	12,212,110
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	139.50	143.24	138.60	136.33	131.03	133.09	
24	AMOUNT	$	148,244,976	152,219,429	147,288,557	144,876,255	139,244,009	141,433,146	
	COAL								
25	PURCHASES:								
26	UNITS	TON	436,874	349,157	371,496	454,678	486,835	491,221	2,590,261
27	UNIT COST	$/TON	81.41	82.05	83.45	80.58	80.62	78.55	80.95
28	AMOUNT	$	35,565,154	28,648,636	31,000,046	36,640,161	39,248,525	38,586,880	209,689,402
29	BURNED:								
30	UNITS	TON	436,874	349,157	371,496	454,678	486,835	491,221	2,590,261
31	UNIT COST	$/TON	81.41	82.05	83.45	80.58	80.62	78.55	80.95
32	AMOUNT	$	35,565,154	28,648,636	31,000,046	36,640,161	39,248,525	38,586,880	209,689,402
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	81.41	82.05	83.45	80.58	80.62	78.55	
36	AMOUNT	$	77,700,803	78,314,138	79,646,179	76,914,902	76,948,213	74,975,539	
	GAS								
37	BURNED:								
38	UNITS	MCF	13,094,387	12,099,265	12,472,278	12,574,756	16,403,942	17,713,816	84,358,444
39	UNIT COST	$/MCF	5.57	5.67	5.63	5.70	5.30	5.22	5.49
40	AMOUNT	$	72,901,750	68,544,788	70,205,554	71,732,815	86,917,387	92,436,008	462,738,302
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2014

	HEAVY OIL		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
1	PURCHASES:								
2	UNITS	BBL	0	0	0	0	0	0	0
3	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	AMOUNT	$	0	0	0	0	0	0	0
5	BURNED:								
6	UNITS	BBL	0	0	0	0	0	0	0
7	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	AMOUNT	$	0	0	0	0	0	0	0
9	ENDING INVENTORY:								
10	UNITS	BBL	0	0	0	0	0	0	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	23,431	23,873	11,626	17,309	6,141	7,190	180,452
15	UNIT COST	$/BBL	131.26	131.12	133.77	131.43	138.22	135.75	133.40
16	AMOUNT	$	3,075,537	3,130,137	1,555,189	2,274,850	848,820	976,007	24,072,649
17	BURNED:								
18	UNITS	BBL	23,431	23,873	11,626	17,309	6,141	7,190	180,452
19	UNIT COST	$/BBL	131.26	131.12	133.77	131.43	138.22	135.75	133.40
20	AMOUNT	$	3,075,537	3,130,137	1,555,189	2,274,850	848,820	976,007	24,072,649
21	ENDING INVENTORY:								
22	UNITS	BBL	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	1,062,688	
23	UNIT COST	$/BBL	131.26	131.12	133.77	131.43	138.22	135.75	
24	AMOUNT	$	139,488,427	139,339,651	142,155,774	139,669,084	146,884,735	144,259,896	
	COAL								
25	PURCHASES:								
26	UNITS	TON	504,335	515,293	493,941	417,832	346,604	405,523	5,273,789
27	UNIT COST	$/TON	77.92	77.34	76.90	73.65	77.96	74.53	78.66
28	AMOUNT	$	39,296,182	39,851,367	37,982,278	30,772,346	27,019,808	30,222,011	414,833,394
29	BURNED:								
30	UNITS	TON	504,335	515,293	493,941	417,832	346,604	405,523	5,273,789
31	UNIT COST	$/TON	77.92	77.34	76.90	73.65	77.96	74.53	78.66
32	AMOUNT	$	39,296,182	39,851,367	37,982,278	30,772,346	27,019,808	30,222,011	414,833,394
33	ENDING INVENTORY:								
34	UNITS	TON	954,458	954,458	954,458	954,458	954,458	954,458	
35	UNIT COST	$/TON	77.92	77.34	76.90	73.65	77.96	74.53	
36	AMOUNT	$	74,368,313	73,815,205	73,394,384	70,293,636	74,405,537	71,131,937	
	GAS								
37	BURNED:								
38	UNITS	MCF	18,716,332	19,499,283	17,357,273	14,828,803	12,514,788	13,268,196	180,543,119
39	UNIT COST	$/MCF	5.19	5.16	5.28	5.51	5.51	5.53	5.41
40	AMOUNT	$	97,217,072	100,696,992	91,659,104	81,728,203	68,938,977	73,419,682	976,398,332
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jan-14	ECONSALE	--	9,138		9,138	4.088	4.947	373,584	452,037	78,453
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	69,005		69,005	3.408	3.408	2,351,878	2,351,878	0
	TOTAL		78,143		78,143	3.488	3.588	2,725,462	2,803,915	78,453
Feb-14	ECONSALE	--	16,831		16,831	4.645	5.620	781,759	945,928	164,169
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	56,913		56,913	3.968	3.968	2,258,404	2,258,404	0
	TOTAL		73,744		73,744	4.123	4.345	3,040,163	3,204,332	164,169
Mar-14	ECONSALE	--	999		999	2.800	3.388	27,975	33,850	5,875
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	37,355		37,355	4.121	4.121	1,539,442	1,539,442	0
	TOTAL		38,354		38,354	4.087	4.102	1,567,417	1,573,292	5,875
Apr-14	ECONSALE	--	1,400		1,400	3.463	4.190	48,483	58,665	10,182
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	58,245		58,245	4.016	4.016	2,339,292	2,339,292	0
	TOTAL		59,645		59,645	4.003	4.020	2,387,775	2,397,957	10,182
May-14	ECONSALE	--	29,079		29,079	3.309	4.003	962,079	1,164,115	202,036
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	71,478		71,478	3.903	3.903	2,789,663	2,789,663	0
	TOTAL		100,557		100,557	3.731	3.932	3,751,742	3,953,778	202,036
Jun-14	ECONSALE	--	276		276	2.712	3.282	7,485	9,057	1,572
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	85,611		85,611	3.666	3.666	3,138,492	3,138,492	0
	TOTAL		85,887		85,887	3.663	3.665	3,145,977	3,147,549	1,572

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Jul-14	ECONSALE	--	3,085		3,085	4.040	4.888	124,621	150,791	26,170
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	114,965		114,965	3.708	3.708	4,263,386	4,263,386	0
	TOTAL		118,050		118,050	3.717	3.739	4,388,007	4,414,177	26,170
Aug-14	ECONSALE	--	27,843		27,843	3.906	4.726	1,087,424	1,315,783	228,359
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	126,297		126,297	3.707	3.707	4,681,223	4,681,223	0
	TOTAL		154,140		154,140	3.742	3.891	5,768,647	5,997,006	228,359
Sep-14	ECONSALE	--	206		206	2.947	3.566	6,071	7,346	1,275
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	125,722		125,722	3.729	3.729	4,688,095	4,688,095	0
	TOTAL		125,928		125,928	3.728	3.729	4,694,166	4,695,441	1,275
Oct-14	ECONSALE	--	1,439		1,439	3.307	4.002	47,591	57,585	9,994
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	113,336		113,336	3.819	3.819	4,327,789	4,327,789	0
	TOTAL		114,775		114,775	3.812	3.821	4,375,380	4,385,374	9,994
Nov-14	ECONSALE	--	1,261		1,261	3.273	3.960	41,270	49,937	8,667
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	74,028		74,028	4.291	4.291	3,176,820	3,176,820	0
	TOTAL		75,289		75,289	4.274	4.286	3,218,090	3,226,757	8,667
Dec-14	ECONSALE	--	154		154	1.653	2.000	2,545	3,080	535
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(70,035)	(70,035)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	42,906		42,906	4.101	4.101	1,759,753	1,759,753	0
	TOTAL		43,060		43,060	4.093	3.931	1,762,298	1,692,798	(69,500)
Jan-14	ECONSALE	--	91,711		91,711	3.828	4.632	3,510,887	4,248,174	737,287
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-14	EXCESS GAIN	--	0		0	0.000	0.000	0	(70,035)	(70,035)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	975,861		975,861	3.824	3.824	37,314,237	37,314,237	0
	TOTAL		1,067,572		1,067,572	3.824	3.887	40,825,124	41,492,376	667,252

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Jan-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	14,695			14,695	11.726	11.726	1,723,105
	SOCO Franklin	--	86,202			86,202	5.789	5.789	4,990,359
	SOCO Scherer	--	31,733			31,733	3.659	3.659	1,161,051
	Vandolah (NSG)	--	27,813			27,813	8.960	8.960	2,492,116
	TOTAL		160,443	0	0	160,443	6.461	6.461	10,366,631
Feb-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,594			5,594	19.953	19.953	1,116,177
	SOCO Franklin	--	79,173			79,173	5.922	5.922	4,688,893
	SOCO Scherer	--	29,652			29,652	3.698	3.698	1,096,438
	Vandolah (NSG)	--	16,186			16,186	11.301	11.301	1,829,120
	TOTAL		130,605	0	0	130,605	6.685	6.685	8,730,628
Mar-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	24,005			24,005	9.905	9.905	2,377,686
	SOCO Franklin	--	136,800			136,800	5.024	5.024	6,873,189
	SOCO Scherer	--	36,304			36,304	3.572	3.572	1,296,857
	Vandolah (NSG)	--	32,932			32,932	8.947	8.947	2,946,430
	TOTAL		230,041	0	0	230,041	5.866	5.866	13,494,162
Apr-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	63,208			63,208	7.110	7.110	4,494,050
	SOCO Franklin	--	39,057			39,057	7.244	7.244	2,829,361
	SOCO Scherer	--	35,226			35,226	3.582	3.582	1,261,860
	Vandolah (NSG)	--	55,356			55,356	7.805	7.805	4,320,268
	TOTAL		192,847	0	0	192,847	6.692	6.692	12,905,539
May-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	91,850			91,850	6.619	6.619	6,079,610
	SOCO Franklin	--	61,851			61,851	5.947	5.947	3,678,551
	SOCO Scherer	--	36,674			36,674	3.567	3.567	1,308,069
	Vandolah (NSG)	--	79,357			79,357	7.436	7.436	5,901,373
	TOTAL		269,732	0	0	269,732	6.291	6.291	16,967,603
Jun-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	97,091			97,091	6.525	6.525	6,334,958
	SOCO Franklin	--	214,510			214,510	4.327	4.327	9,280,801
	SOCO Scherer	--	37,423			37,423	3.748	3.748	1,402,758
	Vandolah (NSG)	--	86,404			86,404	7.496	7.496	6,476,766
	TOTAL		435,428	0	0	435,428	5.396	5.396	23,495,283
Jan-14	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	296,443			296,443	7.464	7.464	22,125,586
Jun-14	SOCO Franklin	--	617,593			617,593	5.237	5.237	32,341,154
	SOCO Scherer	--	207,012			207,012	3.636	3.636	7,527,033
	Vandolah (NSG)	--	298,048			298,048	8.041	8.041	23,966,073
	TOTAL		1,419,096	0	0	1,419,096	6.057	6.057	85,959,846

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	90,201			90,201	6.681	6.681	6,026,640
	SOCO Franklin	--	211,249			211,249	4.375	4.375	9,241,527
	SOCO Scherer	--	37,055			37,055	3.753	3.753	1,390,529
	Vandolah (NSG)	--	84,786			84,786	7.674	7.674	6,506,816
	TOTAL		423,291	0	0	423,291	5.473	5.473	23,165,512
Aug-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	92,025			92,025	6.710	6.710	6,174,973
	SOCO Franklin	--	217,052			217,052	4.362	4.362	9,466,897
	SOCO Scherer	--	37,576			37,576	3.743	3.743	1,406,517
	Vandolah (NSG)	--	86,288			86,288	7.633	7.633	6,586,506
	TOTAL		432,941	0	0	432,941	5.459	5.459	23,634,893
Sep-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	72,129			72,129	7.215	7.215	5,204,272
	SOCO Franklin	--	199,154			199,154	4.436	4.436	8,834,987
	SOCO Scherer	--	31,489			31,489	3.837	3.837	1,208,335
	Vandolah (NSG)	--	63,382			63,382	8.485	8.485	5,378,090
	TOTAL		366,154	0	0	366,154	5.633	5.633	20,625,684
Oct-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	73,173			73,173	6.994	6.994	5,117,385
	SOCO Franklin	--	156,300			156,300	4.661	4.661	7,285,561
	SOCO Scherer	--	0			0	0.000	0.000	189,709
	Vandolah (NSG)	--	63,429			63,429	8.123	8.123	5,152,546
	TOTAL		292,902	0	0	292,902	6.058	6.058	17,745,201
Nov-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	17,889			17,889	11.168	11.168	1,997,856
	SOCO Franklin	--	118,982			118,982	5.197	5.197	6,183,070
	SOCO Scherer	--	32,649			32,649	3.831	3.831	1,250,702
	Vandolah (NSG)	--	32,426			32,426	8.947	8.947	2,901,060
	TOTAL		201,946	0	0	201,946	6.107	6.107	12,332,688
Dec-14	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	8,063			8,063	16.043	16.043	1,293,582
	SOCO Franklin	--	103,832			103,832	5.561	5.561	5,773,765
	SOCO Scherer	--	35,031			35,031	3.774	3.774	1,321,914
	Vandolah (NSG)	--	18,578			18,578	11.068	11.068	2,056,236
	TOTAL		165,504	0	0	165,504	6.311	6.311	10,445,497
Jan-14	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	649,923			649,923	7.376	7.376	47,940,294
Dec-14	SOCO Franklin	--	1,624,162			1,624,162	4.872	4.872	79,126,961
	SOCO Scherer	--	380,812			380,812	3.754	3.754	14,294,739
	Vandolah (NSG)	--	646,937			646,937	8.122	8.122	52,547,327
TOTAL			3,301,834	0	0	3,301,834	5.873	5.873	193,909,321

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-14	QUAL. FACILITIES	COGEN	275,552			275,552	4.460	11.769	12,290,083
Feb-14	QUAL. FACILITIES	COGEN	249,724			249,724	4.471	12.536	11,165,902
Mar-14	QUAL. FACILITIES	COGEN	239,285			239,285	4.631	13.047	11,080,558
Apr-14	QUAL. FACILITIES	COGEN	224,672			224,672	4.408	13.372	9,903,257
May-14	QUAL. FACILITIES	COGEN	265,701			265,701	4.520	12.100	12,009,955
Jun-14	QUAL. FACILITIES	COGEN	257,773			257,773	4.529	12.342	11,675,501
Jul-14	QUAL. FACILITIES	COGEN	256,488			256,488	4.574	12.105	11,730,800
Aug-14	QUAL. FACILITIES	COGEN	259,087			259,087	4.577	12.033	11,857,186
Sep-14	QUAL. FACILITIES	COGEN	249,411			249,411	4.589	12.334	11,445,495
Oct-14	QUAL. FACILITIES	COGEN	246,276			246,276	4.635	12.479	11,414,923
Nov-14	QUAL. FACILITIES	COGEN	229,238			229,238	4.663	13.090	10,688,803
Dec-14	QUAL. FACILITIES	COGEN	266,645			266,645	4.619	11.864	12,316,104
TOTAL	QUAL. FACILITIES	COGEN	3,019,852			3,019,852	4.556	12.396	137,578,568

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-14	ECONPURCH	--	4,685	10.983	10.983	514,541	15.046	704,922	190,381
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		7,912	8.006	8.006	633,441	10.412	823,822	190,381
Feb-14	ECONPURCH	--	3,273	13.746	13.746	449,916	18.832	616,385	166,469
	SEPA	--	2,915	3.684	3.684	107,394	3.684	107,394	0
	TOTAL		6,188	9.006	9.006	557,310	11.696	723,779	166,469
Mar-14	ECONPURCH	--	15,939	5.913	5.913	942,489	8.101	1,291,210	348,721
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		19,166	5.538	5.538	1,061,389	7.357	1,410,110	348,721
Apr-14	ECONPURCH	--	16,988	6.295	6.295	1,069,389	8.624	1,465,063	395,674
	SEPA	--	3,123	3.684	3.684	115,065	3.684	115,065	0
	TOTAL		20,111	5.890	5.890	1,184,454	7.857	1,580,128	395,674
May-14	ECONPURCH	--	15,466	8.670	8.670	1,340,888	11.878	1,837,017	496,129
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		18,693	7.809	7.809	1,459,788	10.463	1,955,917	496,129
Jun-14	ECONPURCH	--	19,937	6.479	6.479	1,291,715	8.876	1,769,650	477,935
	SEPA	--	3,123	3.684	3.684	115,065	3.684	115,065	0
	TOTAL		23,060	6.101	6.101	1,406,780	8.173	1,884,715	477,935
Jan-14 THRU Jun-14	ECONPURCH	--	76,288	7.352	7.352	5,608,938	10.07	7,684,247	2,075,309
	SEPA	--	18,842	3.684	3.684	694,224	3.68	694,224	0
	TOTAL		95,130	6.626	6.626	6,303,162	8.807	8,378,471	2,075,309

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-14	ECONPURCH	--	13,228	8.947	8.947	1,183,555	12.258	1,621,471	437,916
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		16,455	7.915	7.915	1,302,455	10.577	1,740,371	437,916
Aug-14	ECONPURCH	--	10,001	11.158	11.158	1,115,921	15.287	1,528,812	412,891
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		13,228	9.335	9.335	1,234,821	12.456	1,647,712	412,891
Sep-14	ECONPURCH	--	20,396	6.446	6.446	1,314,691	8.831	1,801,127	486,436
	SEPA	--	3,123	3.684	3.684	115,065	3.684	115,065	0
	TOTAL		23,519	6.079	6.079	1,429,756	8.147	1,916,192	486,436
Oct-14	ECONPURCH	--	19,522	6.997	6.997	1,365,912	9.586	1,871,300	505,388
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		22,749	6.527	6.527	1,484,812	8.749	1,990,200	505,388
Nov-14	ECONPURCH	--	14,600	6.231	6.231	909,705	8.536	1,246,296	336,591
	SEPA	--	3,123	3.684	3.684	115,065	3.684	115,065	0
	TOTAL		17,723	5.782	5.782	1,024,770	7.681	1,361,361	336,591
Dec-14	ECONPURCH	--	9,829	6.716	6.716	660,077	9.200	904,306	244,229
	SEPA	--	3,227	3.685	3.685	118,900	3.685	118,900	0
	TOTAL		13,056	5.966	5.966	778,977	7.837	1,023,206	244,229
Jan-14 THRU Dec-14	ECONPURCH	--	163,864	7.420	7.420	12,158,799	10.165	16,657,559	4,498,760
	SEPA	--	37,996	3.684	3.684	1,399,954	3.684	1,399,954	0
	TOTAL		201,860	6.717	6.717	13,558,753	8.946	18,057,513	4,498,760

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison
Estimated for the Period of : January through December 2014

	Approved Jan 13 - Dec 13 ($/1000 KWH)	Requested Jan 14 - Dec 14 ($/1000 KWH)	Difference from Current $	Difference from Current %
Base Rate [1]	$53.85	$58.49	$4.64	8.62%
Fuel Cost Recovery	33.93	40.77	6.84	20.16%
Capacity Cost Recovery (CCR)	12.65	10.82	(1.83)	-14.47%
Energy Conservation Cost Recovery (ECCR) [2]	3.06	3.06	0.00	0.00%
Environmental Cost Recovery (ECRC)	4.94	2.43	(2.51)	-50.81%
Nuclear CR3 Uprate	1.28	2.17	0.89	69.53%
Nuclear Levy	3.45	3.45	0.00	0.00%
Subtotal	113.16	121.19	8.03	7.10%
Gross Receipts Tax	2.90	3.11	0.21	7.24%
Total	$116.06	$124.30	$8.24	7.10%

[1] The 2014 Base Rate is an estimate and is subject to change. The request for the 2014 base rate is expected to be filed in September 2013.

[2] The 2014 ECCR rate has not been updated as the projection filing is not due until September 10, 2013.

Calculation of Inverted Residential Fuel Rates

	Annual Units mWh	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues	Inverted Fuel Rates Cents/kWh	Annual Fuel Revenues
Residential Excluding TOU:					
0 - 1,000 kWh	13,912,535	4.359	$ 606,447,396	4.077	$ 567,202,064
Over 1,000 kWh	5,466,580	4.359	238,288,201	5.077	277,533,533
Total	19,379,114		$ 844,735,597		$ 844,735,597

Rate Differential by Tier - Cents per kWh		1.000
Residential Sales:		
Total	19,379,756	
Time of Use	642	
Levelized	19,379,114	

Docket No. 130001-EI
Schedule H1
Exhibit TGF-3, Part 2

Duke Energy Florida
Generating System Comparative Data by Fuel Type

		2011 Actual	2012 Actual	2013 Actual / Estimated	2014 Projection	2012 vs. 2011	2013 vs. 2012	2014 vs. 2013
FUEL COST OF SYSTEM NET GENERATION ($)								
HEAVY OIL		26,337,457	6,890,407	15,007,768	0	-73.8%	117.8%	-100.0%
LIGHT OIL		27,003,569	18,829,066	22,422,499	24,072,649	-30.3%	19.1%	7.4%
COAL		417,837,565	407,895,600	454,834,815	414,833,394	-2.4%	11.5%	-8.8%
GAS		1,177,106,865	1,054,896,646	975,814,038	976,398,332	-10.4%	-7.5%	0.1%
NUCLEAR		7,090	0	0	0	-100.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,648,292,547	1,488,511,720	1,468,079,120	1,415,304,375	-9.7%	-1.4%	-3.6%
SYSTEM NET GENERATION (MWH)								
HEAVY OIL		188,973	45,476	108,766	0	-75.9%	139.2%	-100.0%
LIGHT OIL		112,555	72,093	61,916	40,224	-35.9%	-14.1%	-35.0%
COAL		10,777,441	10,034,864	11,193,356	11,714,340	-6.9%	11.5%	4.7%
GAS		23,569,365	23,997,245	21,739,703	23,077,814	1.8%	-9.4%	6.2%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MWH	34,648,334	34,149,677	33,103,741	34,832,378	-1.4%	-3.1%	5.2%
UNITS OF FUEL BURNED								
HEAVY OIL	BBL	380,151	89,246	198,144	0	-76.5%	122.0%	-100.0%
LIGHT OIL	BBL	256,528	163,136	175,723	180,452	-36.4%	7.7%	2.7%
COAL	TON	4,662,952	4,543,203	5,101,439	5,273,789	-2.6%	12.3%	3.4%
GAS	MCF	183,772,214	187,422,970	169,172,281	180,543,119	2.0%	-9.7%	6.7%
NUCLEAR	MMBTU	0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)								
HEAVY OIL		2,401,597	568,459	1,215,364	0	-76.3%	113.8%	-100.0%
LIGHT OIL		1,479,408	925,480	1,017,907	1,045,921	-37.4%	10.0%	2.8%
COAL		109,385,876	106,599,484	118,961,743	124,284,918	-2.5%	11.6%	4.5%
GAS		186,092,945	189,832,950	170,194,466	180,543,119	2.0%	-10.3%	6.1%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	299,359,826	297,926,373	291,389,480	305,873,958	-0.5%	-2.2%	5.0%
GENERATION MIX (% MWH)								
HEAVY OIL		0.55%	0.13%	0.33%	0.00%	-73.4%	150.4%	-91.2%
LIGHT OIL		0.33%	0.21%	0.19%	0.12%	-30.8%	0.0%	-53.5%
COAL		31.11%	29.39%	33.81%	33.63%	-5.5%	15.0%	-0.6%
GAS		68.03%	70.27%	65.67%	66.25%	3.2%	-6.5%	0.9%
NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
FUEL COST PER UNIT								
HEAVY OIL	$/BBL	69.28	77.21	75.74	0.00	11.4%	-1.9%	-100.0%
LIGHT OIL	$/BBL	105.27	115.42	127.60	133.40	9.6%	10.6%	4.5%
COAL	$/TON	89.61	89.78	89.16	78.66	0.2%	-0.7%	-11.8%
GAS	$/MCF	6.41	5.63	5.77	5.41	-12.1%	2.5%	-6.2%
NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
HEAVY OIL		10.97	12.12	12.35	0.00	10.5%	1.9%	-100.0%
LIGHT OIL		18.25	20.35	22.03	23.02	11.5%	8.3%	4.5%
COAL		3.82	3.83	3.82	3.34	0.2%	-0.1%	-12.7%
GAS		6.33	5.56	5.73	5.41	-12.1%	3.2%	-5.7%
NUCLEAR		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	$/MMBTU	5.51	5.00	5.04	4.63	-9.3%	0.8%	-8.2%
BTU BURNED PER KWH (BTU/KWH)								
HEAVY OIL		12,709	12,500	11,174	0	-1.6%	-10.6%	-100.0%
LIGHT OIL		13,144	12,837	16,440	26,002	-2.3%	28.1%	58.2%
COAL		10,150	10,623	10,628	10,610	4.7%	0.0%	-0.2%
GAS		7,896	7,911	7,829	7,823	0.2%	-1.0%	-0.1%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	BTU/KWH	8,640	8,724	8,802	8,781	1.0%	0.9%	-0.2%
GENERATED FUEL COST PER KWH (C/KWH)								
HEAVY OIL		13.94	15.15	13.80	0.00	8.7%	-8.9%	-100.0%
LIGHT OIL		23.99	26.12	36.21	59.85	8.9%	38.7%	65.3%
COAL		3.88	4.06	4.06	3.54	4.8%	0.0%	-12.8%
GAS		4.99	4.40	4.49	4.23	-12.0%	2.1%	-5.7%
NUCLEAR		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	C/KWH	4.76	4.36	4.43	4.06	-8.4%	1.7%	-8.4%

CONFIDENTIAL – PART 3

Docket 130001-EI
Exhibit No. ____(TGF-3)
Part 3

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2014

PART 3 – 2014 CAPACITY COST RECOVERY SCHEDULES

Schedule E12-A – Calculation of Projected Capacity Costs

Schedule E12-B – Calculation of Estimated/Actual True-up

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Duke Energy Florida
Calculation Projected Capacity Costs
For the Year 2014

Docket No. 130001-EI
Exhibit__TGF-3, Part 3
Schedule E12-A

		EST Jan-14	EST Feb-14	EST Mar-14	EST Apr-14	EST May-14	EST Jun-14	EST Jul-14	EST Aug-14	EST Sep-14	EST Oct-14	EST Nov-14	EST Dec-14	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Auburndale Power Partners, L.P. (AUBSET)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Lake County (LAKCOUNT)	822,248	822,248	822,248	822,248	822,248	822,248	-	-	-	-	-	-	4,933,488
5	Lake Cogen Limited (LAKORDER)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Metro-Dade County (METRDADE)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Orange Cogen (ORANGECO)	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	3,108,487	37,301,840
8	Orlando Cogen Limited (ORLACOGL)	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	4,395,078	52,740,936
9	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	1,483,270	17,799,240
10	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	3,530,828	42,369,936
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	5,999,259	71,991,105
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,611,352
13	Southern Scherer	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	18,343,440
14	Subtotal - Base Level Capacity Costs	21,668,735	21,668,735	21,668,735	21,668,735	21,668,735	21,668,735	20,846,487	20,846,487	20,846,487	20,846,487	20,846,487	20,846,487	255,091,337
15	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
16	Base Level Jurisdictional Capacity Costs	20,127,005	20,127,004	20,127,004	20,127,004	20,127,004	20,127,005	19,363,260	19,363,260	19,363,260	19,363,260	19,363,260	19,363,260	236,941,585
17	**Intermediate Production Level Capacity Costs**													
18	Southern Franklin	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	25,956,000
19	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
20	Subtotal - Intermediate Level Capacity Costs	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	25,778,496
21	Intermediate Production Jurisdict. Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
22	Intermediate Level Jurisdict. Capacity Costs	1,561,812	1,561,812	1,561,812	1,561,812	1,561,813	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	18,741,742
23	**Peaking Production Level Capacity Costs**													
24	Chattahoochee	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	12,231	146,769
25	Shady Hills	1,968,252	1,968,252	1,405,894	1,363,927	1,909,498	3,881,947	3,881,947	3,881,947	1,811,575	1,363,927	1,363,927	1,968,252	26,769,345
26	Vandolah (NSG)	2,703,924	2,719,493	1,929,521	1,907,278	2,626,076	5,488,291	5,471,609	5,427,124	2,561,202	1,868,354	1,912,839	2,719,493	37,335,203
27	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Subtotal - Peaking Level Capacity Costs	4,684,406	4,699,976	3,347,646	3,283,436	4,547,804	9,382,468	9,365,786	9,321,302	4,385,008	3,244,512	3,288,997	4,699,976	64,251,318
29	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
30	Peaking Level Jurisdictional Capacity Costs	4,493,470	4,508,405	3,211,196	3,149,603	4,362,436	9,000,039	8,984,037	8,941,365	4,206,275	3,112,266	3,154,937	4,508,405	61,632,434
31	**Other Capacity Costs**													
32	Retail Wheeling	(14,527)	(26,756)	(1,588)	(2,226)	(46,227)	(439)	(4,904)	(44,262)	(327)	(2,288)	(2,005)	(245)	(145,793)
33	**Total Capacity Costs (line 16+22+30+32)**	26,167,760	26,170,465	24,898,423	24,836,194	26,005,026	30,688,416	29,904,204	29,822,175	25,131,019	24,035,050	24,078,004	25,433,232	317,169,968
34	Estimated/Actual True-Up Provision - Jan - Dec 2013													24,360,251
35	**Total Capacity Costs w/ True-Up**													341,530,218
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Capacity Costs**													341,776,120
38	**Nuclear Cost Recovery Clause**													174,226,557
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													174,352,000
41	**Total Recov Capacity & Nuclear Costs (line 37+40)**													516,128,120

REDACTED

Duke Energy Florida
Calculation of Projected Capacity Costs
For the Year 2014

Docket No. 130001-EI
Exhibit__TGF-3, Part 3
Schedule E12-A

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Lake County (LAKCOUNT)	Jan-95	Jun-14	QF	Purch	12.75
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	74.00
3	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
4	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
5	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
6	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Dec-23	QF	Purch	39.60
8	Southern - Franklin	Jun-10	May-16	Other	Purch	350.00
9	Southern Wholesale - Scherer 3	Jun-10	May-16	Other	Purch	73.00
10	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	[redacted]
11	Chattahoochee	Jan-03	Dec-17	Other	Purch	
12	Vandolah (NSG)	Jun-12	May-27	Other	Puch	
13	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either DEF or NSB upon 1 year's written notice.

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2013

Docket No. 130001-EI
Exhibit__TGF-2, Part 2
Schedule E12-B

		ACT Jan-13	ACT Feb-13	ACT Mar-13	ACT Apr-13	ACT May-13	ACT Jun-13	EST Jul-13	EST Aug-13	EST Sep-13	EST Oct-13	EST Nov-13	EST Dec-13	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$824,670	$9,896,040
3	Auburndale Power Partners, L.P. (AUBSET)	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	3,611,259	43,335,107
4	Lake County (LAKCOUNT)	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	773,160	9,277,920
5	Lake Cogen Limited (LAKORDER)	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	3,735,759	-	-	-	-	-	26,150,313
6	Metro-Dade County (METRDADE)	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	1,402,230	-	15,424,530
7	Orange Cogen (ORANGECO)	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	2,957,505	35,490,064
8	Orlando Cogen Limited (ORLACOGL)	2,951,657	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	2,879,413	34,625,199
9	Pasco County Resource Recovery (PASCOUNT)	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	1,394,720	16,736,640
10	Pinellas County Resource Recovery (PINCOUNT)	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	3,320,040	39,840,480
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	5,708,711	68,504,529
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	797,588	800,946	777,222	794,026	799,869	794,685	800,946	800,946	800,946	800,946	800,946	800,946	9,570,012
13	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Southern - Scherer	1,716,577	1,716,976	1,717,736	1,740,639	2,398,835	1,599,329	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	1,528,620	20,061,811
15	Subtotal - Base Level Capacity Costs	29,193,876	29,125,389	29,102,424	29,142,132	29,806,171	29,001,481	28,937,033	25,201,274	25,201,274	25,201,274	25,201,274	23,799,044	328,912,645
16	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
17	Base Level Jurisdictional Capacity Costs	27,116,731	27,053,117	27,031,787	27,068,669	27,685,462	26,938,026	26,878,163	23,408,203	23,408,203	23,408,203	23,408,203	22,105,742	305,510,510
18	**Intermediate Production Level Capacity Costs**													
19	Southern - Franklin	3,053,631	3,057,021	3,056,255	3,541,434	3,052,407	2,469,707	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	2,163,000	31,208,455
20	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Intermediate Level Capacity Costs	3,038,839	3,042,229	3,041,463	3,526,642	3,037,615	2,454,915	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	2,148,208	31,030,951
23	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
24	Intermediate Level Jurisdictional Capacity Costs	2,209,327	2,211,792	2,211,235	2,563,975	2,208,437	1,784,797	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	1,561,812	22,560,432
25	**Peaking Production Level Capacity Costs**													
26	Chattahoochee	12,500	11,290	13,710	12,231	12,769	12,231	12,231	12,231	12,231	12,231	12,231	12,231	148,115
27	Vandolah (RRI)	2,925,728	2,887,475	1,965,866	1,940,723	2,792,514	5,785,174	-	-	-	-	-	-	18,297,480
28	Shady Hills Power Company LLC	1,965,615	1,973,145	1,406,700	1,363,500	1,908,900	3,840,480	3,881,947	3,881,947	1,811,575	1,363,927	1,363,927	1,968,252	26,729,915
29	Vandolah (NSG)	-	-	-	-	-	-	5,471,609	5,427,124	2,561,202	1,868,354	1,912,839	2,719,493	19,960,621
30	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Subtotal - Peaking Level Capacity Costs	4,903,844	4,871,910	3,386,276	3,316,454	4,714,183	9,637,885	9,365,786	9,321,302	4,385,008	3,244,512	3,288,997	4,699,976	65,136,132
32	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
33	Peaking Level Jurisdictional Capacity Costs	4,703,963	4,673,331	3,248,251	3,181,275	4,522,033	9,245,045	8,984,037	8,941,365	4,206,275	3,112,266	3,154,937	4,508,405	62,481,183
34	**Other Capacity Costs**													
35	Retail Wheeling	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(19,040)	(9,745)	(2,218)	(11,347)	(2,518)	(1,540)	(74,525)
36	Other Jurisdictional Capacity Costs	(1,983)	(1,594)	(16,373)	(7,586)	(237)	(344)	(19,040)	(9,745)	(2,218)	(11,347)	(2,518)	(1,540)	(74,525)
37	**Subtotal Jurisd Capacity Costs (Line 17+24+33+36)**	34,028,038	33,936,646	32,474,900	32,806,333	34,415,695	37,967,523	37,404,972	33,901,635	29,174,072	28,070,933	28,122,434	28,174,418	390,477,600
38	**Nuclear Cost Recovery Clause Costs**													
39	Levy Costs	8,475,072	11,483,103	8,258,947	8,021,598	8,162,758	8,305,060	8,248,615	8,312,931	8,330,438	8,271,575	8,179,250	8,647,553	102,696,902
40	CR3 Uprate Costs	3,358,869	3,354,735	3,350,601	3,346,468	3,342,335	3,338,203	3,334,071	3,329,940	3,325,809	3,321,678	3,317,548	3,313,419	40,033,676
41	**Total NCRC Costs - Order No. PSC-12-0650-FOF-EI**	11,833,942	14,837,838	11,609,549	11,368,066	11,505,094	11,643,262	11,582,686	11,642,871	11,656,247	11,593,253	11,496,798	11,960,972	142,730,579
42	**Total Jurisdictional Capacity Costs (Line 37+41)**	45,861,980	48,774,484	44,084,449	44,174,399	45,920,789	49,610,786	48,987,658	45,544,506	40,830,319	39,664,187	39,619,232	40,135,390	533,208,179
43	**Capacity Revenues**													
44	Capacity Cost Recovery Revenues (net of tax)	37,233,908	36,928,525	36,311,578	38,376,446	43,163,088	48,265,348	51,923,538	54,322,575	54,369,943	47,492,236	41,168,481	39,591,723	529,147,389
45	Prior Period True-Up Provision Over/(Under) Recovery	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(873,802)	(10,485,622)
46	**Current Period Revenues (net of tax)**	36,360,106	36,054,723	35,437,776	37,502,644	42,289,286	47,391,546	51,049,737	53,448,773	53,496,141	46,618,434	40,294,679	38,717,921	518,661,767
47	**True-Up Provision**													
48	True-Up Provision - Over/(Under) Recov (Line 46-42)	(9,501,874)	(12,719,761)	(8,646,672)	(6,671,754)	(3,631,503)	(2,219,239)	2,062,079	7,904,267	12,665,822	6,954,247	675,447	(1,417,470)	(14,546,411)
49	Interest Provision for the Month	(1,425)	(2,785)	(3,569)	(3,599)	(3,341)	(2,887)	(3,211)	(3,791)	(4,374)	(4,955)	(5,533)	(6,120)	(45,590)
50	Current Cycle Balance - Over/(Under)	(9,503,299)	(22,225,844)	(30,876,086)	(37,551,438)	(41,186,283)	(43,408,409)	(41,349,541)	(33,449,065)	(20,787,617)	(13,838,325)	(13,168,411)	(14,592,001)	(14,592,001)
51	Prior Period Balance - Over/(Under) Recovered	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)	(20,253,872)
52	Prior Period Cumulative True-Up Collected/(Refunded)	873,802	1,747,604	2,621,405	3,495,207	4,369,009	5,242,811	6,116,613	6,990,415	7,864,216	8,738,018	9,611,820	10,485,622	10,485,622
53	Prior Period True-up Balance - Over/(Under)	(19,380,070)	(18,506,268)	(17,632,466)	(16,758,664)	(15,884,862)	(15,011,061)	(14,137,259)	(13,263,457)	(12,389,655)	(11,515,853)	(10,642,051)	(9,768,250)	(9,768,250)
54	**Net Capacity True-up Over/(Under) (Line 50+53)**	($28,883,369)	($40,732,112)	($48,508,552)	($54,310,103)	($57,071,145)	($58,419,470)	($55,486,799)	($46,712,522)	($33,177,272)	($25,354,179)	($23,810,463)	($24,360,251)	($24,360,251)

Duke Energy Florida
Calculation of Energy and Demand Percent by Rate Class
Using 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2014

Docket No. 130001-EI
Exhibit__TGF-3, Part 3
Schedule E12-D

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (MWh)	(3) Avg 12 CP at Meter (MW)	(4) Delivery Efficiency Factor	(5) Sales at Source (Generation) (MWh)	(6) Avg 12 CP at Source (MW)	(7) Annual Average Demand (MWh)	(8) Annual Average Demand Allocator (%)	(9) 12CP Allocator (%)	(10) **12CP 1/13 AD** Demand Allocator (%)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS-1										
Secondary	0.519	19,379,756	4,262.80	0.9401722	20,612,986	4,534.07	2,353.08	51.673%	62.173%	61.365%
General Service Non-Demand										
GS-1, GST-1										
Secondary	0.652	1,238,682	216.84	0.9401722	1,317,506	230.64	150.40	3.303%	3.163%	3.173%
Primary	0.652	3,675	0.64	0.9744331	3,771	0.66	0.43	0.009%	0.009%	0.009%
Transmission	0.652	3,551	0.62	0.9844331	3,607	0.63	0.41	0.009%	0.009%	0.009%
								3.321%	3.180%	3.191%
General Service										
GS-2 Secondary	1.000	138,834	15.85	0.9401722	147,669	16.86	16.86	0.370%	0.231%	0.242%
General Service Demand										
GSD-1, GSDT-1										
Secondary	0.774	11,976,648	1,766.38	0.9401722	12,738,782	1,878.78	1,454.20	31.934%	25.762%	26.237%
Transm Del/ Primary Mtr	0.774	720	0.11	0.9744331	739	0.11	0.08	0.002%	0.001%	0.002%
Sec Del/Primary Mtr	0.774	45,041	6.64	0.9744331	46,223	6.82	5.28	0.116%	0.093%	0.095%
Primary	0.774	2,367,758	349.21	0.9744331	2,429,883	358.37	277.38	6.091%	4.914%	5.005%
SS-1 Primary	1.483	7	0.00	0.9744331	7	0.00	0.00	0.000%	0.000%	0.000%
Transm Del/ Primary Mtr	1.483	2,313	0.18	0.9744331	2,374	0.18	0.27	0.006%	0.003%	0.003%
Transmission	1.483	10,052	0.77	0.9844331	10,211	0.79	1.17	0.026%	0.011%	0.012%
								38.174%	30.785%	31.353%
Curtailable										
CS-1, CST-1, CS-2, CST-2, SS-3										
Primary	1.186	57,212	5.51	0.9744331	58,713	5.65	6.70	0.147%	0.077%	0.083%
SS-3 Primary	0.814	2,198	0.31	0.9744331	2,256	0.32	0.26	0.006%	0.004%	0.004%
								0.153%	0.082%	0.087%
Interruptible										
IS-1, IST-1, IS-2, IST-2										
Secondary	0.963	96,011	11.38	0.9401722	102,121	12.11	11.66	0.256%	0.166%	0.173%
Sec Del/Primary Mtr	0.963	4,547	0.54	0.9744331	4,666	0.55	0.53	0.012%	0.008%	0.008%
Primary Del / Primary Mtr	0.963	1,201,675	142.48	0.9744331	1,233,204	146.22	140.78	3.091%	2.005%	2.089%
Primary Del / Transm Mtr	0.963	17,669	2.09	0.9844331	17,948	2.13	2.05	0.045%	0.029%	0.030%
Transm Del/ Primary Mtr	0.963	321,079	38.07	0.9744331	329,503	39.07	37.61	0.826%	0.536%	0.558%
Transm Del/ Transm Mtr	0.963	285,799	33.89	0.9844331	290,318	34.42	33.14	0.728%	0.472%	0.492%
SS-2 Primary	0.859	58,388	7.76	0.9744331	59,920	7.97	6.84	0.150%	0.109%	0.112%
Transm Del/ Primary Mtr	0.859	15,284	2.03	0.9744331	15,685	2.09	1.79	0.039%	0.029%	0.029%
Transmission	0.859	48,896	6.50	0.9844331	49,669	6.60	5.67	0.125%	0.091%	0.093%
								5.272%	3.444%	3.584%
Lighting										
LS-1 (Secondary)	6.141	388,984	7.23	0.9401722	413,737	7.69	47.23	1.037%	0.105%	0.177%
Total		37,664,779	6,877.84		39,891,498	7,292.71	4,553.82	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2012 (FPSC rule 25-6.0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2014
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2012
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4
(7) Calculated: Column 6 / 8,760 hours
(8) Calculated: Column 7 / Total Column 7
(9) Calculated: Column 6 / Total Column 6
(10) Calculated: Column 8 x 1/13 + Column 9 x 12/13

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2014

Docket No. 130001-EI
Exhibit__TGF-3, Part 3
Schedule E12-E
Page 1 of 2

Rate Class	(1) **12CP 1/13 AD** Demand Allocator (%)	(2) Effective mWh at Secondary Level (MWh)	(3) Capacity Production Demand Costs ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(7) Capacity CCR Factor (c/kWh)	(8) Levy CCR Factor (c/kWh)	(9) CR3 CCR Factor (c/kWh)	(10) Capacity & Nuclear CCR Factor (c/kWh)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS-1										
Secondary	61.365%	19,379,756	$209,730,507	$66,860,158	$42,121,182	$318,711,848	**1.082**	**0.345**	**0.217**	**1.644**
General Service Non-Demand										
GS-1, GST-1										
Secondary		1,238,682					**0.875**	**0.252**	**0.176**	**1.303**
Primary		3,638					**0.866**	**0.249**	**0.174**	**1.290**
Transmission		3,480					**0.858**	**0.247**	**0.172**	**1.277**
TOTAL GS	3.191%	1,245,800	10,906,650	3,139,417	2,190,435	16,236,501				
General Service										
GS-2 Secondary	0.242%	138,834	826,569	252,678	166,004	1,245,250	**0.595**	**0.182**	**0.120**	**0.897**
General Service Demand										
GSD-1, GSDT-1, SS-1										
Secondary		11,976,648								
Primary		2,391,681								
Transmission		9,851								
TOTAL GSD	31.353%	14,378,180	107,157,853	31,634,330	21,521,025	160,313,208				
Curtailable										
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3										
Secondary		-								
Primary		58,816								
Transmission		-								
TOTAL CS	0.087%	58,816	298,275	146,637	59,904	504,815				
Interruptible										
IS-1, IST-1, IS-2, IST-2, SS-2										
Secondary		96,011								
Primary		1,584,963								
Transmission		345,317								
TOTAL IS	3.584%	2,026,291	12,250,879	3,475,973	2,460,403	18,187,255				
Lighting										
LS-1 Secondary	0.177%	388,984	605,388	202,272	121,583	929,242	**0.156**	**0.052**	**0.031**	**0.239**
Total	100.000%	37,616,661	$341,776,120	$105,711,465	$68,640,535	$516,128,120	**0.909**	**0.282**	**0.182**	**1.373**

Notes:

(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) (Column 8 x Column 2) x 10
(5) Column 1 x Total Recoverable Payments (Schedule E12-A)
(6) Column 3 + Column 4 + Column 5
(7) (Column 3 / Column 2) / 10
(8) (Column 4 / Column 2) / 10
(9) (Column 5 / Column 2) / 10
(10) Column 7 + Column 8 + Column 9
(11) Class Billing kW Load Factor
(12) Column 2 x 1000 / 8760 / Column 11 x 12
(13) Column 3 / Column 12
(14) Column 4 / Column 12
(15) Column 5 / Column 12
(16) Column 6 / Column 12

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2014

Docket No. 130001-EI
Exhibit__TGF-3, Part 3
Schedule E12-E

Rate Class	(1) **12CP 1/13 AD** Demand Allocator (%)	(2) Effective mWh at Secondary Level (MWh)	(3) Capacity Production Demand Costs ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(11) Billing KW Load Factor (%)	(12) Projected Effective KW at Meter Level (kW)	(13) Capacity CCR Factor ($/kW-mo)	(14) Levy CCR Factor ($/kW-mo)	(15) CR3 CCR Factor ($/kW-mo)	(16) Capacity & Nuclear CCR Factor ($/kW-mo)
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	61.365%	19,379,756	$209,730,507	$66,860,158	$42,121,182	$318,711,848						
General Service Non-Demand												
GS-1, GST-1												
Secondary		1,238,682										
Primary		3,638										
Transmission		3,480										
TOTAL GS	3.191%	1,245,800	10,906,650	3,139,417	2,190,435	16,236,501						
General Service												
GS-2 Secondary	0.242%	138,834	826,569	252,678	166,004	1,245,250						
General Service Demand												
GSD-1, GSDT-1, SS-1												
Secondary		11,976,648							**2.85**	**0.84**	**0.57**	**4.26**
Primary		2,391,681							**2.82**	**0.83**	**0.56**	**4.22**
Transmission		9,851							**2.79**	**0.82**	**0.56**	**4.17**
TOTAL GSD	31.353%	14,378,180	107,157,853	31,634,330	21,521,025	160,313,208	52.30%	37,659,917				
Curtailable												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
Secondary		-							**1.85**	**0.91**	**0.37**	**3.13**
Primary		58,816							**1.83**	**0.90**	**0.37**	**3.10**
Transmission		-							**1.81**	**0.89**	**0.36**	**3.07**
TOTAL CS	0.087%	58,816	298,275	146,637	59,904	504,815	50.00%	161,139				
Interruptible												
IS-1, IST-1, IS-2, IST-2, SS-2												
Secondary		96,011							**2.43**	**0.69**	**0.49**	**3.61**
Primary		1,584,963							**2.41**	**0.68**	**0.49**	**3.57**
Transmission		345,317							**2.38**	**0.68**	**0.48**	**3.54**
TOTAL IS	3.584%	2,026,291	12,250,879	3,475,973	2,460,403	18,187,255	55.10%	5,037,643				
Lighting												
LS-1 Secondary	0.177%	388,984	605,388	202,272	121,583	929,242						
Total	100.000%	37,616,661	$341,776,120	$105,711,465	$68,640,535	$516,128,120						

Notes:
(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) (Column 8 x Column 2) x 10
(5) Column 1 x Total Recoverable Payments (Schedule E12-A)
(6) Column 3 + Column 4 + Column 5
(7) (Column 3 / Column 2) / 10
(8) (Column 4 / Column 2) / 10
(9) (Column 5 / Column 2) / 10
(10) Column 7 + Column 8 + Column 9
(11) Class Billing kW Load Factor
(12) Column 2 x 1000 / 8760 / Column 11 x 12
(13) Column 3 / Column 12
(14) Column 4 / Column 12
(15) Column 5 / Column 12
(16) Column 6 / Column 12

***Calculation of Standby Service kW Charges:**

	Capacity + Nuclear Cost		
	Cost	Effective kW	$/kW
Total GSD, CS, IS	$179,005,278	42,858,699	4.18

SS-1, 2, 3 - $/kW-mo	Secondary	Primary	Trans
Monthly - $4.18/kW * 10%	0.418	0.414	0.410
Daily - $4.18/kW / 21	0.199	0.197	0.195

REDACTED

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Summary by Commodity for 2012

Progress Energy Florida
Natural Gas and Oil Hedging Detail

Natural Gas

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (MMBtu's): Financial	Physical	Total Hedged	Actual Burn (Generation & Tolling)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-12	[redacted]						16,323,000	[redacted]		
Feb-12							13,991,600			
Mar-12							15,685,400			
Apr-12							14,631,400			
May-12							17,498,100			
Jun-12							17,557,200			
Jul-12							21,147,700			
Aug-12							20,655,500			
Sep-12							19,079,500			
Oct-12							17,232,800			
Nov-12							13,942,100			
Dec-12							15,603,800			
YTD	($351,321,610)	$0	($351,321,610)	136,150,000	0	136,150,000	203,526,200	67%	100%	0%

No. 6 Oil

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Barrels): Financial	Physical	Total Hedged	Actual Burn (Generation)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-12	[redacted]						11,200	[redacted]		
Feb-12							200			
Mar-12							3,800			
Apr-12							7,300			
May-12							9,800			
Jun-12							200			
Jul-12							20,500			
Aug-12							31,000			
Sep-12							5,000			
Oct-12							25			
Nov-12							257			
Dec-12							0			
YTD	$4,456,315	$0	$4,456,315	40,000	0	40,000	89,282	45%	100%	0%

No. 2 Oil

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Barrels): Financial	Physical	Total Hedged	Actual Burn (Generation)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-12	[redacted]						12,300	[redacted]		
Feb-12							15,800			
Mar-12							13,100			
Apr-12							14,200			
May-12							10,500			
Jun-12							15,700			
Jul-12							30,200			
Aug-12							18,200			
Sep-12							9,800			
Oct-12							6,884			
Nov-12							7,432			
Dec-12							7,906			
YTD	$382,080	$0	$382,080	71,000	0	71,000	163,022	44%	100%	0%

Natural Gas Storage

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (MMBtu's): Financial	Physical	Total Hedged	Storage Injections	Hedged Injections	% Hedged with Financial	% Hedged with Physical
Jun-12	[redacted]						250,000	[redacted]		
YTD	($205,913)	$0	($205,913)	150,000	0	150,000	250,000	60%	100%	0%

Heating Oil - River Barge - Fuel Surcharge Hedges

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Gallons): Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical
Jan-12	[redacted]						449,178	[redacted]		
Feb-12							448,023			
Mar-12							448,852			
Apr-12							497,612			
May-12							489,779			
Jun-12							500,511			
Jul-12							500,042			
Aug-12							535,395			
Sep-12							536,605			
Oct-12							534,725			
Nov-12							513,182			
Dec-12							515,159			
YTD	$432,198	$0	$432,198	2,898,000	0	2,898,000	5,979,043	48%	100%	0%

Heating Oil - Rail - Fuel Surcharge Hedges

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Gallons): Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical
Jan-12	[redacted]						227,371	[redacted]		
Feb-12							204,634			
Mar-12							173,553			
Apr-12							173,553			
May-12							173,553			
Jun-12							257,044			
Jul-12							257,044			
Aug-12							257,044			
Sep-12							257,044			
Oct-12							257,044			
Nov-12							176,906			
Dec-12							176,906			
YTD	$476,755	$0	$476,755	1,260,000	0	1,260,000	2,591,695	49%	100%	0%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Joesph McCallister - JM-1T
EXHIBIT 26A

Hedging Details for "Natural Gas" (Aug – Dec 2012)

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3118864	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3118864	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3121520	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3121520	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3368670	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3368670	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3372221	CSEL	IFERC	HHUB			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3372221	CSEL	IFERC	HHUB			$3.0100			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3491513	DEU#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3491513	DEU#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3514188	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3514188	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	CALL	8/1/2012	3516638	CITI#	NYMEX	NG			$3.0100			
Financial	FIXED FINANCIAL OPTION	PUT	8/1/2012	3516638	CITI#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2126526	JPMC#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2130399	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2140259	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2165072	CSEL	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2181905	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2194795	MACQ#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2209416	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2220222	MSCG	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2244145	MSCG	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2262119	MSCG	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2287613	CSEL	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2298911	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2304857	CSEL	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2334860	CSEL	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2372713	JPMC#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2403490	JPMC#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2407826	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2437253	BOM#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2441273	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2450449	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2457822	UBS	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2468935	UBS	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2479689	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2579384	JPMC#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	2619064	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2640230	BOM#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2655370	MLC	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2950205	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2978485	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	2992078	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3011635	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3040398	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3058997	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3075920	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3079512	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3084029	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3092421	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3097817	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3100805	CSEL	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3107669	DEU#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3122705	CSEL	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3159298	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3161687	MLC	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3170806	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3182046	BAR#	NYMEX	NG			$3.0100			

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		8/1/2012	3200030	CITI#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3201402	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3201573	JPMC#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3213921	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3218240	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3224666	SG#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3270901	BAR#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3277276	CSEL	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3296304	SG#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3299485	CITI#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3301247	CSEL	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3309077	MACQ#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3329744	SG#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3334005	MACQ#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3341161	DEU#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3346901	MSCG	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3349570	SG#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3350847	DEU#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3353522	FEMT	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3354889	MACQ#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3366686	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3369620	MACQ#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3371625	SG#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3371666	CEH#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3372231	MSCG	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3372261	CEH#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3373795	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3374367	MACQ#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3379030	MSCG	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3383887	DEU#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3388491	BOM#	IFERC	HHUB			$3.0100			
Financial	FIXED SWAP		8/1/2012	3394490	CEH#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3399664	CEH#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3455145	SG#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3461718	CEH#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3463105	SG#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3472728	CEH#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3478150	BPCNA#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3479619	BOM#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3488200	FEMT	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3502069	CSEL	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3503800	CONC	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3508795	BAR#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3509358	BPCNA#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3521408	BOM#	NYMEX	NG			$3.0100			
Financial	FIXED SWAP		8/1/2012	3523050	CONC	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3523341	BPCNA#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3526023	BOM#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3529156	JPMC#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3536388	JPMC#	IFERC	TRNSZ4			$3.0200			
Financial	FIXED SWAP		8/1/2012	3549971	BOM#	IFERC	MAINLN			$2.9600			
												20,655,500	71%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 3 of 16

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3118865	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3118865	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3121521	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3121521	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3368671	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3368671	MSCG	NYMEX	NG			$2.6340			

Docket No. 130001-EI
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Hedging Details (Aug - Dec 2012)
Page 4 of 16

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3372222	CSEL	IFERC	HHUB			$2.6300			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3372222	CSEL	IFERC	HHUB			$2.6300			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3491514	DEU#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3491514	DEU#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3514189	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3514189	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	CALL	9/1/2012	3516639	CITI#	NYMEX	NG			$2.6340			
Financial	FIXED FINANCIAL OPTION	PUT	9/1/2012	3516639	CITI#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2126527	JPMC#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2130402	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2140261	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2165073	CSEL	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2181906	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2194796	MACQ#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2209417	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2220223	MSCG	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2244146	MSCG	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2262120	MSCG	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2287614	CSEL	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2298912	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2304858	CSEL	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2334861	CSEL	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2372714	JPMC#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2403492	JPMC#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2407827	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2437255	BOM#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2441274	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2450450	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2457823	UBS	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2468936	UBS	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2479690	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2579385	JPMC#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	2619065	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2640231	BOM#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2655371	MLC	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2950206	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2978487	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	2992079	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3011636	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3040399	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3058998	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3075921	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3079513	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3084030	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3092422	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3097818	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3100806	CSEL	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3107670	DEU#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3122706	CSEL	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3159299	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3161688	MLC	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3170807	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3182047	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3200031	CITI#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3201403	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3201574	JPMC#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3213922	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3218241	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3224667	SG#	NYMEX	NG			$2.6340			

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		9/1/2012	3270902	BAR#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3277277	CSEL	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3296305	SG#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3299486	CITI#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3301248	CSEL	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3309078	MACQ#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3329745	SG#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3334006	MACQ#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3341162	DEU#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3346902	MSCG	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3349571	SG#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3350848	DEU#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3353523	FEMT	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3354890	MACQ#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3366687	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3369623	MACQ#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3371626	SG#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3371667	CEH#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3372232	MSCG	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3372262	CEH#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3373796	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3374368	MACQ#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3379031	MSCG	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3383888	DEU#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3388492	BOM#	IFERC	HHUB			$2.6300			
Financial	FIXED SWAP		9/1/2012	3394491	CEH#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3399665	CEH#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3455146	SG#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3461719	CEH#	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3463106	SG#	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3472729	CEH#	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3478151	BPCNA#	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3479620	BOM#	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3488201	FEMT	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3502070	CSEL	NYMEX	NG			$2.6340			
Financial	FIXED SWAP		9/1/2012	3503801	CONC	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3508796	BAR#	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3509359	BPCNA#	IFERC	TRNSZ4			$2.5900			
Financial	FIXED SWAP		9/1/2012	3549972	BOM#	IFERC	MAINLN			$2.5500			
												19,079,500	69%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 6 of 16

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2012	3118866	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2012	3118866	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2012	3121522	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2012	3121522	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2012	3368672	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2012	3368672	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2012	3372223	CSEL	IFERC	HHUB			$3.0600			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2012	3372223	CSEL	IFERC	HHUB			$3.0600			
Financial	FIXED FINANCIAL OPTION	CALL	10/1/2012	3491515	DEU#	NYMEX	NG			$3.0230			
Financial	FIXED FINANCIAL OPTION	PUT	10/1/2012	3491515	DEU#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2126528	JPMC#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2130405	DEU#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2140262	DEU#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2165074	CSEL	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2181907	DEU#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2194797	MACQ#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2209418	DEU#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2220224	MSCG	IFERC	HHUB			$3.0600			

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		10/1/2012	2244147	MSCG	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2262121	MSCG	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2287615	CSEL	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2298913	DEU#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2304859	CSEL	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2334862	CSEL	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2372715	JPMC#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2403494	JPMC#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2407828	DEU#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2437256	BOM#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2441275	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2450451	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2457824	UBS	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2468937	UBS	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2479691	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2579386	JPMC#	IFERC	HHUB			$3.0600			
Financial	FIXED SWAP		10/1/2012	2619066	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2640232	BOM#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2655372	MLC	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2950207	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2978488	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	2992080	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3011637	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3040400	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3058999	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3075922	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3079514	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3084031	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3092423	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3097819	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3100807	CSEL	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3107671	DEU#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3122707	CSEL	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3159300	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3161689	MLC	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3170808	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3182049	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3200032	CITI#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3201404	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3201575	JPMC#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3213923	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3218242	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3224668	SG#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3270903	BAR#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3277278	CSEL	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3296306	SG#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3299487	CITI#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3301249	CSEL	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3309079	MACQ#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3329746	SG#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3334007	MACQ#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3341163	DEU#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3346903	MSCG	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3349572	SG#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3350849	DEU#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3353524	FEMT	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3371627	SG#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3371668	CEH#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3394492	CEH#	NYMEX	NG			$3.0230			

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		10/1/2012	3399666	CEH#	NYMEX	NG	[redacted]	[redacted]	$3.0230	[redacted]		
Financial	FIXED SWAP		10/1/2012	3455147	SG#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3461720	CEH#	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3463107	SG#	IFERC	TRNSZ4			$2.9700			
Financial	FIXED SWAP		10/1/2012	3472730	CEH#	IFERC	TRNSZ4			$2.9700			
Financial	FIXED SWAP		10/1/2012	3478153	BPCNA#	IFERC	TRNSZ4			$2.9700			
Financial	FIXED SWAP		10/1/2012	3479621	BOM#	IFERC	TRNSZ4			$2.9700			
Financial	FIXED SWAP		10/1/2012	3488202	FEMT	IFERC	TRNSZ4			$2.9700			
Financial	FIXED SWAP		10/1/2012	3502071	CSEL	NYMEX	NG			$3.0230			
Financial	FIXED SWAP		10/1/2012	3503806	CONC	IFERC	TRNSZ4			$2.9700			
Financial	FIXED SWAP		10/1/2012	3508797	BAR#	IFERC	TRNSZ4			$2.9700			
												17,232,800	67%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 9 of 16

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2012	3118867	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2012	3118867	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2012	3121523	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2012	3121523	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2012	3368673	MSCG	NYMEX	NG			$3.4710			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2012	3368673	MSCG	NYMEX	NG			$3.4710			
Financial	FIXED FINANCIAL OPTION	CALL	11/1/2012	3372224	CSEL	IFERC	HHUB			$3.4700			
Financial	FIXED FINANCIAL OPTION	PUT	11/1/2012	3372224	CSEL	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	2209419	DEU#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	2244148	MSCG	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	2262122	MSCG	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	2372716	JPMC#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	2625161	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	2640233	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	2656077	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3202226	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3207064	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3213902	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3217517	DEU#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3222397	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3225052	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3231883	DEU#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3274072	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3295354	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3297998	MACQ#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3301231	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3309046	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3312392	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3321928	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3329691	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3334008	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3341164	MSCG	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3347571	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3349578	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3353525	DEU#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3355365	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3367372	CEH#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3371628	DEU#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3371669	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3372241	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3373818	MACQ#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3377740	MSCG	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3379136	JPMC#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3383968	CSEL	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3386624	MACQ#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3395981	BAR#	NYMEX	NG			$3.4710			

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 10 of 16

PEF Gas Hedging Status

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		11/1/2012	3448434	CSEL	NYMEX	NG	[redacted]	[redacted]	$3.4710	[redacted]		
Financial	FIXED SWAP		11/1/2012	3456970	CITI#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3461246	BAR#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3472646	BAR#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	3478076	CEH#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3479622	DEU#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3490396	CEH#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3502914	BOM#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	3508826	DEU#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	3514190	BOM#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	3522740	SG#	NYMEX	NG			$3.4710			
Financial	FIXED SWAP		11/1/2012	3526026	CEH#	IFERC	HHUB			$3.4700			
Financial	FIXED SWAP		11/1/2012	3534314	CEH#	IFERC	HHUB			$3.4700			
												13,942,100	57%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 11 of 16

Hedging Details for "No. #6 Oil" (Aug – Dec 2012)

PEF #6 Oil Hedging Status

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/Bbl)	Market Scan Biz Average ($/Bbl)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	8/1/2012	2634208	MSCG	NYHRBR	NO61	[redacted]	[redacted]	$108.9550	[redacted]		
Financial	FIXED SWAP	8/1/2012	3632698	DEU#	NYHRBR	NO61			$108.9550			
											31,000	16%
Financial	FIXED SWAP	9/1/2012	2634210	MSCG	NYHRBR	NO61			$107.2550			
Financial	FIXED SWAP	9/1/2012	3508891	MACQ#	NYHRBR	NO61			$107.2550			
											5,000	100%
Financial	FIXED SWAP	10/1/2012	2634212	MSCG	NYHRBR	NO61			$101.9790			
Financial	FIXED SWAP	10/1/2012	3508895	MACQ#	NYHRBR	NO61			$101.9790			
											25	20000%
Financial	FIXED SWAP	11/1/2012	2634214	MSCG	NYHRBR	NO61			$98.6330			
Financial	FIXED SWAP	11/1/2012	3350976	MLC	NYHRBR	NO61			$98.6330			
Financial	FIXED SWAP	11/1/2012	3627487	JPMC#	NYHRBR	NO61			$98.6330			
											257	0%
Financial	FIXED SWAP	12/1/2012	2634216	MSCG	NYHRBR	NO61			$96.2730			
Financial	FIXED SWAP	12/1/2012	3350978	MLC	NYHRBR	NO61			$96.2730			
Financial	FIXED SWAP	12/1/2012	3627491	JPMC#	NYHRBR	NO61			$96.2730			
											0	#DIV/0!

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 12 of 16

Hedging Details for "No. #2 Oil" (Aug – Dec 2012)

PEF #2 Oil Hedging Status

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume (Bbls)	Fixed Price ($/Bbl)	Market Scan Biz Average ($/Bbl)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	8/1/2012	3196547	MLC	NYMEX	HOIND	[redacted]	[redacted]	$128.2501	[redacted]		
Financial	FIXED SWAP	8/1/2012	3220839	DEU#	NYMEX	HOIND			$128.2501			
											19,200	36%
Financial	FIXED SWAP	9/1/2012	3196548	MLC	NYMEX	HOIND			$132.1183			
Financial	FIXED SWAP	9/1/2012	3220841	DEU#	NYMEX	HOIND			$132.1183			
											9,800	71%
Financial	FIXED SWAP	10/1/2012	3338607	MLC	NYMEX	HOIND			$131.8820			
Financial	FIXED SWAP	10/1/2012	3375121	BOM#	NYMEX	HOIND			$131.8820			
											6,884	145%
Financial	FIXED SWAP	11/1/2012	3338609	MLC	NYMEX	HOIND			$126.5146			
Financial	FIXED SWAP	11/1/2012	3375125	BOM#	NYMEX	HOIND			$126.5146			
Financial	FIXED SWAP	11/1/2012	3673996	MSCG	USGLF	NO2ULS			$125.6514			
											7,432	67%
Financial	FIXED SWAP	12/1/2012	3338611	MLC	NYMEX	HOIND			$125.7913			
Financial	FIXED SWAP	12/1/2012	3375127	BOM#	NYMEX	HOIND			$125.7913			
Financial	FIXED SWAP	12/1/2012	3673997	MSCG	USGLF	NO2ULS			$124.2528			
											7,906	63%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)

Hedging Details for "Gas Storage" (Aug – Dec 2012)

PEF Gas Storage Hedging Status

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged

NO STORAGE ACTIVITY FOR AUGUST THROUGH DECEMBER 2012

Hedging Details for "Coal Transportation – River Barge" (Aug – Dec 2012)

PEF Coal Transportation Hedging Status - Barge

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	8/1/2012	3196535	NYMEX	HOIND	[redacted]	[redacted]	$3.0536	[redacted]		
Financial	FIXED SWAP	8/1/2012	3376625	NYMEX	HOIND			$3.0536			
Financial	FIXED SWAP	8/1/2012	3392235	NYMEX	HOIND			$3.0536			
Financial	FIXED SWAP	8/1/2012	3494720	NYMEX	HOIND			$3.0536			
										535,395	55%
Financial	FIXED SWAP	9/1/2012	3196537	NYMEX	HOIND			$3.1457			
Financial	FIXED SWAP	9/1/2012	3376627	NYMEX	HOIND			$3.1457			
Financial	FIXED SWAP	9/1/2012	3392237	NYMEX	HOIND			$3.1457			
Financial	FIXED SWAP	9/1/2012	3494722	NYMEX	HOIND			$3.1457			
										536,605	55%
Financial	FIXED SWAP	10/1/2012	3376629	NYMEX	HOIND			$3.1400			
Financial	FIXED SWAP	10/1/2012	3398160	NYMEX	HOIND			$3.1400			
Financial	FIXED SWAP	10/1/2012	3674006	USGLF	NO2ULS			$3.1512			
										534,725	31%
Financial	FIXED SWAP	11/1/2012	3376631	NYMEX	HOIND			$2.9203			
Financial	FIXED SWAP	11/1/2012	3398164	NYMEX	HOIND			$2.9200			
Financial	FIXED SWAP	11/1/2012	3674008	USGLF	NO2ULS			$3.1300			
										513,162	33%
Financial	FIXED SWAP	12/1/2012	3376633	NYMEX	HOIND			$2.9950			
Financial	FIXED SWAP	12/1/2012	3398166	NYMEX	HOIND			$2.9950			
Financial	FIXED SWAP	12/1/2012	3674010	USGLF	NO2ULS			$2.9584			
										515,159	33%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 15 of 16

Hedging Details for "Coal Transportation - Rail" (Aug – Dec 2012)

PEF Coal Transportation Hedging Status - Rail

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	8/1/2012	3196541	NYMEX	HOIND	[redacted]	[redacted]	$3.0536	[redacted]		
Financial	FIXED SWAP	8/1/2012	3621717	USGLF	NO2ULS			$3.1456			
										257,044	49%
Financial	FIXED SWAP	9/1/2012	3196543	NYMEX	HOIND			$3.1457			
Financial	FIXED SWAP	9/1/2012	3621719	USGLF	NO2ULS			$3.1873			
										257,044	49%
Financial	FIXED SWAP	10/1/2012	3398154	NYMEX	HOIND			$3.1400			
										257,044	33%
Financial	FIXED SWAP	11/1/2012	3398156	NYMEX	HOIND			$3.0123			
										176,906	47%
Financial	FIXED SWAP	12/1/2012	3398158	NYMEX	HOIND			$2.9950			
										176,906	47%

Docket No. 130001-EI
Witness: McCallister
Exhibit No. ___ (JM-1T)
Hedging Details (Aug - Dec 2012)
Page 16 of 16

FILED AUG 30, 2013
DOCUMENT NO. 05174-13
FPSC - COMMISSION CLERK

EXHIBIT NO. ___ (JM-1P)

REDACTED

"2014 RISK MANAGEMENT PLAN"
(originally filed on August 2, 2013)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 27
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Joesph McCallister - JM-1P

FILED AUG 02, 2013
DOCUMENT NO. 04492-13
FPSC - COMMISSION CLERK

130001-EI

REDACTED

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ___ (JM-1P)
Page 1 of 68

Duke Energy Florida, Inc.
Risk Management Plan for
Fuel Procurement and Wholesale Power Purchases
For 2014

Duke Energy Florida, Inc. (DEF) is submitting its 2014 Risk Management Plan for review by the Florida Public Service Commission. The Risk Management Plan includes the required items as outlined in Attachment A of Order No. PSC-02-1484-FOF-EI and specifically items 1 through 9, and items 13 through 15 as set forth in Exhibit TFB-4 to the prefiled testimony of Todd F. Bohrmann in Docket No. 011605-EI and further clarified in Order No. PSC-08-0667-PAA-EI of Docket No. 080001-EI.

Several groups play key roles in the management, monitoring, and execution of the activities outlined in DEF's Risk Management Plan. These groups include Fuels and System Optimization (FSO), Global Risk Management (GRM), which includes Enterprise and Regulated Risk and Credit (Risk Management), Regulated Accounting, Internal Audit, Legal, and Information Technology. The activities supported by these groups include the following: procuring competitively priced fuel, performing active asset optimization and portfolio management, executing DEF's hedging strategy, monitoring and reporting against established oversight limits for credit and margin limits, performing credit evaluations and monitoring credit and default exposure, performing deal validation, volume actualization, preparing and reviewing transactions and contracts, preparing journal entries to account for fuel and power related activities, performing billing and payments under the various fuel and purchased power contracts, performing audits, and maintaining and supporting needed systems to capture, track, and account for these activities.

Based on the July 2013 Fuels and Operations Forecast (FOF), DEF's estimated fuel consumption and economy transaction projections for 2014 are as follows:

Coal
Based on current projections, DEF forecasts to burn approximately [redacted] tons of coal in 2014. DEF's forecasted coal requirements for 2014 will primarily be purchased under term coal supply agreements. The coal supply will be delivered to DEF's plants via railroad and barge transportation agreements. Spot purchases will be made as needed to supplement the term purchases.

Light Oil
Based on current projections, DEF forecasts to burn approximately [redacted] barrels of light oil in 2014. DEF's forecasted light fuel oil requirements for 2014 are expected to be purchased primarily under term supply

agreements with volume flexibility at indexed market prices. Spot market purchases will be made as needed to supplement term purchases.

Natural Gas

Based on current projections, DEF forecasts to burn approximately [redacted] of natural gas in 2014, comprised of approximately [redacted] at DEF's generating plants and [redacted] at gas-tolling purchased power facilities where DEF has the responsibility to provide the natural gas. DEF's forecasted natural gas requirements for 2014 are expected to be purchased primarily under term supply agreements based on market index pricing, with supplemental seasonal, monthly and daily purchases of natural gas being made as needed.

Economy Power Purchases and Sales

Based on current projections, DEF forecasts to purchase approximately [redacted] of economy power and sell approximately [redacted] of economy power in 2014. DEF actively seeks to purchase and sell economy power as opportunities arise based on market prices, dispatch costs, and available transmission capacity.

Item 1. **Identify the company's overall quantitative and qualitative Risk Management Plan Objectives.**

DEF's identified 2014 Risk Management Plan Objectives are to effectively manage its overall fuel and purchased power costs for its customers by engaging in competitive fuel procurement practices and activities, performing active asset optimization and portfolio management activities, and continuing to execute the company's hedging program to reduce price risk and provide greater cost certainty for DEF's customers. These items are discussed further in Item 8.

Item 2. **Identify the minimum quantity of fuel to be hedged and the activities to be executed during the remainder of 2013 and during 2014**

DEF utilizes a phased hedging program where hedge transactions are executed over time with the objective of reducing price risk and providing greater cost certainty for DEF's customers. The hedging program includes executing approved agreements over time for natural gas and light fuel oil usage for generation fuel, and coal rail and river transportation fuel surcharges. Natural gas hedging activity represents the largest component of DEF's hedging program as natural gas represents the largest fuel cost component of DEF's overall generation fuel costs.

The volumes hedged over time represent a portion of DEF's forecasted burns with higher hedging target ranges in the near term and lower hedging target ranges in the outer period. The hedge percentage target ranges outlined provide a framework for consistently executing the layered hedging strategy over time. DEF cannot predict future prices and DEF's hedging program does not involve speculation or trying to "out-guess" the market. All hedges are executed at the prevailing market price for any given period that exists at the time the hedging transactions are executed. The results of hedging activities may or may not result in net fuel cost savings due to differences between the monthly settlement prices and the actual hedge price of the transactions that were executed over time. The volumes hedged for each fuel type over time are based on periodic updated fuel forecasts and the actual hedge percentages for any month, rolling period, or calendar annual period may come in higher or lower than the target minimum hedge percentages and hedging ranges because of actual fuel burns versus forecasted fuel burns. Actual burns can deviate from forecasted burns because of dynamic variables such as weather, unforeseen unit outages, actual load, and changing fuel prices. DEF's multi-year approach to executing fixed price transactions over time is a reasonable and prudent approach to reduce price risk and provide greater cost certainty for DEF's customers.

Outlined below for each fuel type and exposure are the targeted minimum hedge percentages to be hedged for the remainder of 2013 and 2014:

Natural Gas

Natural gas represents DEF's largest fuel cost component and represents the largest component of DEF's hedging activities. DEF plans to continue to execute its existing phased hedging program over a rolling 36-month period through time for natural gas through the remainder of 2013 and during 2014. The currently approved rolling hedge percentage that are outlined in DEF's Franchised Electric Risk Limits as follows.

[redacted]

DEF will target to hedge a minimum of [redacted] and [redacted] of forecasted natural gas burns for the rolling 36-month time period through time, respectively, during the remainder of 2013 and 2014. Given DEF's hedging strategy, DEF will continue to participate in spot natural gas prices for a portion of its estimated natural gas needs.

REDACTED

Light Oil

With respect to light oil forecasted to be burned at DEF's owned generation facilities for calendar year 2014, during the balance of 2013 and 2014, DEF will target to hedge a minimum of [redacted] of its forecasted light oil burns.

Coal Rail and River Transportation Fuel Surcharges
During the balance of 2013 and during 2014, with respect to coal river and rail transportation estimated fuel surcharge exposure, DEF will target to hedge between [redacted] to [redacted] of the estimated fuel surcharge exposure for calendar year 2014.

Summary
Through the remainder of 2013 and during 2014, DEF will continue monitor its fuel forecast and will continue to execute hedges over time to attempt to manage to the hedge percentage targets outlined for a portion of its projected burns for natural gas, light oil, and estimated coal rail and river transportation fuel surcharge exposure. This hedging approach is consistent with DEF's existing strategy and allows DEF to continue to monitor the market and fuel forecast updates. The hedging targets for each of the respective periods are included in DEF's Franchised Electric Risk Limits in **Attachment A**.

Item 3. **Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.**

DEF has identified specific and general risks associated with the procurement of fuels and power optimization activities. The specific risks include fuel price risk, supplier performance and default risk, liquidity risk, credit risk, product availability risk, and changes in forecasted volumes. The general risks include weather related events such as hurricanes, extreme weather variations from forecast, business continuity, and changes in environmental rules and regulations. Described below are the specific and general risks and DEF's activities to manage overall exposure to these risks. In addition, the processes that DEF has in place to monitor and quantify these risks are also described.

Fuel Price Risk
DEF's customers are exposed to the risk of fuel price movements, which could result in significant variability in projected and actual fuel costs. For natural gas and light oil, the physical fuel is procured under standard industry contracts that are based on published market index pricing that exists during the time periods the fuel is delivered. The published market index prices paid by DEF for these fuels will fluctuate with daily changes in market prices until the respective first of the month market index or daily-published market index

price settles and the product is delivered. For coal, DEF executes standard industry supply agreements to fix and/or collar the price of the underlying coal, but is exposed to fuel surcharges in the transportation agreements. Absent hedging as defined by Order No. PSC-02-1484-FOF-EI (i.e. the Hedging Order), Order No. PSC-08-0667-PAA-EI (i.e. Clarifying Hedge Order), and PSC-09-0349-CO-EI (i.e. Transportation Surcharges), and fixed price coal supply contracts, the projected fuel costs for coal, natural gas, and light oil fuel purchases could vary significantly due to changing market prices over time.

DEF manages and reduces fuel price risks for a portion of its forecasted natural gas and fuel oil burns, and estimated coal rail and river transportation fuel surcharges by utilizing financial transactions over time. As outlined above, DEF enters into standard industry coal supply agreements to fix the price of the underlying commodity exposure. Because of these actions, DEF reduces its overall exposure to changes in projected fuel costs for its customers.

With respect to monitoring and quantifying fuel price risk, Risk Management independently monitors and reports on the percentage of projected fuel burns that have been hedged under physical and financial agreements as compared to the established procurement targets for each respective product and period. In addition, the Company performs multiple periodic fuel and purchased power cost forecast updates each year, which incorporate any updates needed for financial and physical hedge positions, fuel and emission prices, unit maintenance schedules, load forecasts, and other operating parameters. The updated fuel and purchased power forecasts are point in time estimates and are summarized and published to ensure there is a regular review of projected fuel and purchased power costs. In addition, Risk Management performs standard statistical stress tests and portfolio analysis on an as needed basis.

Supplier Performance and Default Risk
Supplier performance and default risk represents the risk of financial loss and/or supply loss that DEF could incur if a supplier defaults on a physical or financial obligation and is not able to fulfill the terms of an agreement. The estimated aggregate dollar amount of supplier performance and default risk for the portfolio is based on the volume, duration, and price of the agreements as compared to the current estimated market value of the agreements.

DEF reduces supplier performance risk by engaging in business with a number of approved suppliers, executing agreements within contract approval limits and credit parameter limits, monitoring delivery performance of suppliers, and, if possible, incorporating contractual provisions that allow for non-performance remedies in the case of default. In addition, if a supplier defaults, DEF also maintains on-site inventories for coal and fuel oil. For

activities associated with hedging under financial agreements, the Credit function within Risk Management monitors all open positions and reviews the estimated exposure for each third party company on a daily basis to ensure that DEF has the appropriate collateral balances as compared to contractual thresholds established.

With respect to monitoring and quantifying the level of supplier performance and default risk in fuel agreements, the Credit function within Risk Management monitors and reports on the amount of default risk associated with coal, natural gas, and fuel oil financial and physical agreements. The review is based on contractual volumes, duration, and prices as compared to the current estimated value of the open positions in the agreements that have yet to be delivered or financially settled. See **Attachment B** for DEF's estimated Portfolio Default Exposure Report as of July 11, 2013.

Liquidity Risk

Liquidity risk represents the risk that DEF could not meet the collateral requirements generated from fuel hedging agreements if fuel prices fall substantially. As discussed above, DEF manages fuel price risk for a portion of its forecasted fuel costs through the use of physical and financial hedging agreements. To manage default risk, most of these agreements contain provisions that require the posting of collateral if contractual thresholds are surpassed. The collateral requirements of the portfolio are based on the volume, duration, price, and collateral threshold levels of the agreements as compared to the current estimated market value of the agreements.

DEF manages and reduces liquidity risk by conducting business with a number of counterparties to maximize the collateral threshold levels in individual agreements. In addition, DEF has continued to maximize the use of hedging agreements with non-marginable provisions that have less impact on collateral requirements and do not require the posting of margin. For activities associated with hedging under financial agreements, the Credit function within Risk Management monitors all open positions and reviews the estimated market exposure for each third party company on a daily basis to ensure that DEF only posts the appropriate collateral balances as compared to contractual thresholds.

With respect to monitoring and quantifying the level of liquidity risk in fuel agreements, Risk Management independently calculates, monitors, and reports on the amount of liquidity risk associated with coal, natural gas, and fuel oil financial and physical agreements. The review is based on contractual volumes, duration, and prices as compared to the current estimated value of the open positions in the agreements that have yet to be delivered or financially settled. Risk Management performs standard statistical stress tests and portfolio analysis on an as needed basis.

In addition, the company continues to monitor the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). The Dodd-Frank Act provides for the comprehensive regulation of swaps and security-based swaps, applying in respects to all swaps, including the bilateral and over-the-counter (OTC) derivatives markets, as well as swaps embedded in physical forward transactions. Generally, the Dodd-Frank Act provides for certain exemptions from the mandatory clearing and exchange trading requirements for participants that are "end-users" engaging in hedging activities to mitigate or hedge physical risk. DEF enters into commodity and interest rate hedges to mitigate commercial risk and/or hedge physical positions, rather than as part of a regular swap business, thus it is eligible for the end-user exemption from the law's mandatory clearing and trading provisions.

The Commodity Futures Trading Commission (CFTC) issued rules for recordkeeping and reporting requirements and the marketplace is in the process of achieving compliance with these regulations. DEF is maintaining records in accordance with the requirements of the CFTC regulations. Further, as an end-user, DEF can shift, and has shifted, the reporting obligation to swap counterparties for historic and current swap transactions. The CFTC has not finalized the rules for margining and clearing requirements. DEF is continuing to study issued rules and timing of their implementation to prepare for applicable compliance requirements. DEF continues to monitor the potential impact of the rules on its hedging transactions; however, it is difficult to predict how the market will ultimately adjust to the new regulations.

In general, proposed regulations may continue to effect changes to the derivatives markets. For example, margining requirements could raise the incremental cost of hedging activities as it may require counterparties to post additional margin and maintenance margin for OTC derivatives, which would then increase the liquidity requirements needed to support these activities. Currently, DEF has credit collateral thresholds in place with its counterparties that do not require the posting of collateral unless the market value of its hedges drops below the negotiated threshold dollar value. Additionally, DEF has negotiated several bi-lateral non-margin hedging agreements with counterparties where margin posting is not required on certain transactions. If some of DEF's counterparties are subject to higher liquidity requirements due to the proposed regulations, DEF could be subject to higher incremental costs for hedging transactions in the form of 1) potential increases in bid / offer spreads on market hedge transactions, 2) potential reduction by certain counterparties in the use of non marginable OTC transactions, and 3) potential reduction in the number of counterparties who will be available for hedging transactions with DEF.

Credit Risk

On a daily basis, the Credit function within Risk Management calculates, monitors, and reports on the credit risk associated with the Company's fuel procurement and hedging activities. The Credit function utilizes industry-specific credit evaluation practices and has specific criteria that are used to measure credit risk and ensure counterparties' credit is monitored and reviewed. The Credit function monitors all positions and reviews the mark-to-market exposure for each third party company to ensure that based on the current market value of open hedge positions and the credit quality of the third party companies the appropriate level of collateral is posted or received as compared to the contractually established threshold. To date, DEF has not experienced any credit losses with respect to its hedging program activities.

With respect to financial transactions, prior to executing any financial transaction with a third party company, two activities take place. First, DEF and the third party company must have an International Swap Dealer Agreement (ISDA) in place. The ISDA is a standard industry contract that is used by industry participants to enter into Over the Counter bi-lateral transactions (OTC transactions). All ISDA agreements are negotiated by the Legal group and reviewed as needed with Credit, FSO, and Accounting to ensure the appropriate terms and conditions are included. As part of the process of setting up a new financial agreement, a credit evaluation is performed on the third party company by the Credit function. There are universal principles of credit strength that are evaluated before credit is granted. Among these principles are company size, industry characteristics and trends, profitability, liquidity, cash flow, interest and fixed charge coverage, and capital structure. DEF evaluates counterparties using a consistent analytical approach and the credit ratings are based on both external ratings and the evaluation of key counterparty attributes identified as leading indicators for financial performance. The credit rating process includes obtaining counterparty background information, identifying any existing Standard & Poor's (S&P) and/or Moody's ratings for the counterparty, and performing a financial statement analysis. The financial statement analysis includes, but is not limited to, a review of revenue trends, metric calculations and trends evaluation for Free Funds from Operations, Total Debt to Tangible Net Worth, Funded Debt to Capital, Interest Coverage, Operating Cash Flow and Liquidity. If the counterparty is a bank, Tier I and Total Capital Ratios are also reviewed. Once the credit evaluation is complete, a credit rating is assigned to the third party company and, if appropriate, a credit line is extended. The assigned credit rating and credit limit dictate the size and duration of financial hedging transactions that DEF can enter into with a third party company.

As described, on a daily basis the Credit function independently monitors, calculates and reports on collateral exposure. In addition, with respect to monitoring agreements that require the posting of margin based on established contractual thresholds, the company may ask for margin or send out margin to the third party company to ensure exposures are within established contractual thresholds. See **Attachment C** for the DEF Collateral Report as of July 11, 2013.

Product Availability and Changes in Forecasted Volumes

DEF must have access to needed physical fuel supplies, adequate product delivery capabilities and inventory to meet projected fuel requirements. Without access to needed fuel supply and inventory, DEF is exposed to the risk of not being able to economically and reliably dispatch the generation fleet for its customers.

DEF manages and reduces this risk by entering into physical supply contracts, as well as needed pipeline, railroad, barge, and trucking agreements for the purchase and delivery of coal, natural gas, and fuel oil that provide the ability to meet projected burns. In addition, DEF maintains on-site inventory for coal and fuel oil to provide fuel supplies to support on-going operations and ensure supplies are available if unexpected delivery delays, storm curtailments, or other events that could affect fuel supply availability occur. DEF also holds off-site high deliverability natural gas storage capacity that provides additional access for a portion of its natural gas needs when natural gas supplies are curtailed. In addition, DEF has firm transportation on Gulfstream Natural Gas, Florida Gas Transmission (FGT), and Southern Natural Gas (Sonat), and has access to onshore gas supplies via contractual volumes delivered on Southeast Supply Header, the Transco Mobile Bay South Lateral and purchase for LNG volumes that are delivered out of Elba Island into FGT via the Sonat Cypress Pipeline. DEF monitors actual fuel burns, forecasted fuel burns, and fuel inventory levels. Based on these reviews, DEF may make procurement adjustments to manage any changes to the volume and delivery timing of contracted supplies because of actual burns, changes to forecasted fuel burns, and inventory levels that can be caused by economic factors, weather deviations, fuel-switching trends, plant outages, and purchased power opportunities.

With respect to monitoring and quantifying the level of risk associated with ensuring adequate fuel supply, Risk Management independently monitors and reports on the amount of fuel procured versus projected burns. In addition, the front office performs analyses that quantify the amount of fuel and transportation needed to support projected burns and inventory needs Lastly, the Company performs periodic forecast for fuel burns and purchased power and produces summary reports for review and monitoring of projected fuel burns.

General Risk
DEF is subject to weather events and hurricanes. As detailed above, DEF reduces the overall risks associated with weather events and other potential fuel delivery curtailments and delays by maintaining on-site inventories, off-site inventories, and continuing to diversify its natural gas supply to more secure onshore locations as the Company's overall gas generation has grown. DEF is also subject to events that could require FSO employees to perform required work functions at locations other than their normal work location. With respect to this risk, the FSO Department has business continuity plans in place that are reviewed and tested periodically to ensure that offsite locations are functional. Lastly, DEF is subject to changes in environmental rules and regulations.

Item 4. Describe the company's oversight of its fuel procurement activities.

The Finance and Risk Management Committee (FRMC) of the Board of Directors as well as the Company's Senior Management, defined as the Chief Executive Officer (CEO) and his/her direct reports, provide guidance and oversight to Duke Energy's financial risks. The Chief Risk Officer (CRO) updates the FRMC of any material risks or risk taking activities of the enterprise at every regularly scheduled Board meeting. The Transaction and Risk Committee (TRC) is responsible for oversight of the Corporation's Risk Management activities. The TRC is comprised of senior executives from varying functional areas. The CRO is responsible for annually reviewing the corporate Commodity Risk Policy and Corporate Credit Policy, and the TRC is responsible for approving substantive changes to the policies. The CRO reviews corporate risks and resulting mitigation decisions including fuel hedging and procurement activities. The TRC reviews transactions that exceed individual senior management committee approval authorities. Senior management committee approval authorities are outlined in the Company's Approval of Business Transaction policy (ABT). In addition, the Company maintains a risk management control manual, together with specific risk and credit limits that apply to the activities of DEF. These policies, processes, and limits are reviewed at least annually by the Front Office and Risk Management, and are approved by CRO or the Chief Financial Officer (CFO) as required.

DEF has included the Franchised Electric Risk Management Control Manual, the Commodity Risk Policy, The Credit Policy, the DEF Franchised Electric Risk Limits and the DEF Franchised Electric Credit Limits as **Attachments I, E, F, A and G.**

With respect to day-to-day independent oversight and controls in place to oversee FSO's activities, the company uses the "three-office" structure which includes FSO and Energy Supply Analytics (Front Office), Risk Management (Middle Office), and Regulated Accounting (Back Office) to provide the necessary independent oversight and monitoring of its fuel procurement, power optimization, and hedging activities

The "three-office' structure is an accepted industry practice with the Front Office, Middle Office, and Back Office each functioning as independent departments, which ensures the required segregation of duties and the existence of independent oversight and controls over key activities. In addition, the Legal organization provides critical contractual support to ensure that the Front Office contracts are reviewed with FSO and contain legal provisions that reduce risks that could affect the Company. The IT Enterprise Application Solution Support organization provides on-going support related to trading system operations and functioning. Treasury and Disbursement Services provide appropriate support when disbursing funds to counterparties via checks, wires, or automated clearinghouse payments. These support organizations are independent from the Front Office.

Front Office
DEF has a structured procurement process where Requests for Proposals are issued periodically to procure needed competitive fuel supply. As noted above, the fuel procurement contracting and settlement activity is supported by the Legal and Regulated Accounting function. Front Office management is responsible for ensuring employees are authorized before they are allowed to trade commodities on the Company's behalf. In addition, there is a corporate Energy Supply Bulk Power Marketing & Trading Delegation of Authorities as well as a corporate Approval of Business Transactions Delegation of Authorities, which provides the required approvals for fuel related procurement activity based on estimated costs and duration of fuel related contracts. Front Office management is also responsible for ensuring that employees who trade commodities on the company's behalf attend required periodic training conducted by Risk Management and Regulatory Compliance. DEF has included the Duke Energy Commodity Risk Policy, Duke Energy Credit Policy, DEF Franchised Electric Risk Limits and DEF Franchised Electric Credit Limits in **Attachments E, F, A, and G.** In addition, DEF has included the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authorities and the Duke Energy Commodities Approval Matrix from the ABT as **Attachments H and D** respectively.

Middle Office
Risk Management monitors Front Office activity by quantifying, monitoring, and reporting risks associated with fuel procurement, power optimization, and hedging activities. Risk Management is accountable to the enterprise for

independent oversight, measurement, and reporting of Front Office activities to management. Risk Management monitors and reports on Front Office activities and will report immediately any non-compliance as required within the reporting and control limit structures as defined by the Risk Management Guidelines. Lastly, Risk Management publishes credit limit and exposure reports to ensure that counterparty credit limits are monitored and adhered to and administers margin activity as required under agreements with counterparties to reduce credit and default risk.

Regulated Accounting
Accounting is also independent from Front Office and performs the following control functions, among other things, on a daily, weekly, or monthly basis: deal validation, transaction confirmations, close accounting, general ledger balance sheet account reconciliations, settlements/cash transfers, processing payments/receipts, accounting for hedging activities and derivatives, and performing certain compliance activities as defined and/or required by various regulatory agencies (e.g. Securities and Exchange Commission, Financial Accounting Standards Board, Federal Energy Regulatory Commission, Public Service Commission). Related to accounting for hedging activities and derivatives, Duke Energy's Derivatives policy is followed. This policy is reviewed and updated as necessary and at least annually.

Item 5. **Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.**

As described in Item 4, the Company has a robust independent oversight culture and organizational design with processes in place to ensure the identification, monitoring, and reporting of risks accompanying independent controls for monitoring and reporting on fuel procurement, power optimization, and hedging activities. The key components of the oversight functions and processes are further described below.

The Finance and Risk Management Committee of the Board of Directors (FRMC)
The FRMC is primarily responsible for the oversight of risk at the Company. This oversight function includes, but is not limited to, review of Duke Energy's risk exposure as related to the overall company portfolio and impact on earnings and review of the financial exposures undertaken by the company in light of the approved Corporate Risk Management Policies. Such exposures include physical and financial positions in the commodities markets. The Committee is comprised of a minimum of two members of the Board

Transaction and Risk Committee (TRC)

The TRC is responsible for oversight of the Corporation's Risk Management activities as well as reviewing proposed business transactions and risk management activities that require approval by the President and Chief Executive Officer, the Board of Directors, or a committee of the Board of Directors in accordance with the Approval of Business Transactions Policy. The membership of the Committee shall consist of the following officers of the Corporation:

- Chief Financial Officer (Chair)
- Chief Legal Officer
- Vice President and Chief Risk Officer
- Vice President and Treasurer
- Vice President, Internal Audit, Ethics and Compliance

In addition to the members listed above, three members from the Senior Management Committee, other than the Chief Financial Officer and Chief Legal Officer who are permanent members, serve on the Committee on a rotational basis. These members will be selected on an annual basis by the President and Chief Executive Officer.

Enterprise and Regulated Risk Management (Risk Management)
The Company has an independent Risk Management section, which is overseen by the Director of Enterprise Portfolio and Risk Management who reports to the CRO. The Risk Management group is comprised of a credit risk management function and a market risk management function. Risk Management's credit function provides independent credit evaluation of trading and procurement counterparties, performs credit reviews of the Company's suppliers and customers, assists in drafting and reviewing credit language in various agreements, and monitors and reports on credit exposures daily. Risk Management's market risk function independently reports on fuel procurement and hedging activities and performs independent analysis as required Risk Management independently develops the methodologies for measuring and evaluating risk.

Franchised Electric Risk Management Control Manual and Franchised Electric Risk Limits
As part of the overall risk management structure and oversight process at the Company, the Company has a Franchised Electric Risk Management Control Manual, Franchised Electric Risk Limits and Franchised Electric Credit Limits.

These are reviewed by Front Office and Risk Management, and approved by the CRO or the CFO as required.

The Franchised Electric Risk Management Control Manual provides the descriptions of the objectives and operations of the regulated businesses, the overall control environment in which they operate, and the structure and responsibilities of the various groups involved in the control function. DEF's Franchised Electric Risk Limits contain the limits and approved activities for DEF. In aggregate, these documents provide for the oversight and controls, roles and responsibilities, and the approved activities associated with fuel procurement contracts, fuel hedging activities, and power activities. Duke Energy's Credit Policy provides the overall objectives and general operating practices for evaluating, measuring, mitigating, and reporting credit risk associated with FSO activities. In addition, the Company has established Credit Risk Limits define prescribed credit limits, including contract duration criteria for counterparties based on credit metrics.

Internal Audit
Internal Audit provides independent assurance and consulting services that ensure compliance, effective corporate governance, adherence to established procedures, and operational effectiveness for all major areas of the Company. With respect to FSO activities, Audit Services performs periodic audits that focus on items such as compliance with established procedures, off-premise activity, payment terms under fuel contracts, and other trading and procurement activities.

Legal and Regulated Accounting
Legal performs contract reviews with the Front Office during drafting and prior to final execution. In addition, Regulated Accounting which includes the Back Office performs, among other things, on a daily, weekly, or monthly basis, deal validation, transaction confirmations, close accounting, general ledger balance sheet account reconciliations, settlements/cash transfers, processing payments/receipts, accounting for hedging activities and derivatives, and compliance activities as defined and required.

Item 6. Describe the utility's corporate risk policy regarding fuel procurement activities.

The Company has a Franchised Electric Risk Management Control Manual, a Commodity Risk Policy, a Credit Policy, and Franchised Electric Risk and Electric Credit Limits. In addition, the Company has the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority, and the Duke Energy Commodities Approval Matrix from the Approval of Business Transactions policy that outline the approval requirements for procurement

activities for respective individuals and management levels based on the tenor and estimated dollar amounts of agreement, subject to the requirements of the Approval of Business Transactions policy.

These documents and processes in aggregate outline the expectations, policies, responsibilities, and limits associated with the corporate risk oversight and approved activities for the Company's fuel procurement practices. In addition, as described in detail in item 4 the Company has developed oversight functions and processes that are followed with respect to fuel procurement, power optimization, and hedging activities. DEF has included the Franchised Electric Risk Management Control Manual, Duke Energy Commodity Risk Policy, Duke Energy Credit Policy, the Franchised Electric Risk Limits, the Franchised Electric Credit Limits, the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority, and the Duke Energy Commodities Approval Matrix from the ABT as **Attachments I, E, F, A, G, H and D.** The fuel purchase and related activities are identified under the Energy Supply Bulk Power Marketing & Trading Delegation of Authority, Franchised Electric Risk Limits and the Commodities Approval Matrix.

Item 7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement and hedging activities.

The Utility has approval requirements, policies, and authorizations in place that outline authorizations for fuel procurement and hedging activities. DEF has included the DEF's Franchised Electric Risk Limits and corporate Duke Energy Commodity Risk Policy in **Attachment A and E**. These policies and guidelines outline roles and responsibilities of each group, deal execution processes, and allowed products, as well as control limits such as volumetric, tenor, and liquidity limits and deal validation and valuation processes. Additionally, the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority and the Duke Energy Commodities Approval Matrix from the ABT outline the approval requirements for procurement activities for respective individuals and management levels based on the tenor and estimated dollar amounts of agreement, subject to the requirements of the Approval of Business Transactions policy. The Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority, and the Duke Energy Commodities Approval Matrix from the ABT are included in **Attachments, H, and D,** respectively.

Item 8. Describe the utility's strategy to fulfill its risk management objectives.

As outlined in Item 1, DEF's 2014 Risk Management Plan objectives are to effectively manage its overall fuel and purchased power costs for its customers by engaging in competitive fuel procurement practices and activities, performing active asset optimization and portfolio management activities, and continuing to execute the company's hedging program to reduce price risk and provide greater cost certainty for DEF's customers. Outlined below is the strategy to fulfill the risk management objectives.

First, the strategy is executed by experienced professionals who conduct and execute their activities to achieve the objectives of the plan.

One of the components of DEF's Risk Management Plan objectives is to engage is competitive fuel procurement practices. Examples of the strategy executed to fulfill this objective include the issuance of periodic RFP's to solicit competitive term supply bids for coal, natural gas, and fuel oil. In addition, DEF actively manages its day-to-day fuel needs and participates in the short-term market place to access competitive supply and work closely with suppliers as needed. With respect to the strategy executed to achieve the objective of performing active asset optimization and portfolio management activities, the Portfolio Management Unit within FSO performs daily forecast to determine optimal unit commitment and dispatch based on generation costs and market prices, and together with the Power Trading Unit within FSO, monitors the hourly cost to dispatch the generation fleet compared to available market opportunities. The Power Unit actively seeks opportunities to execute economic purchases and sales that reduce costs for the customers. Lastly, with respect to the strategy executed to fulfill the objectives of the hedging program, DEF by virtue of locking in fixed price for a portion of forecasted usage over time via its hedging program, achieves this objective as a portion of DEF's fuel costs are no longer subject to changing fuel markets.

Along with the examples noted above, DEF's Risk Management Plan activities are governed by independent controls and audits, strong processes, appropriate organizational design and oversight, deal approval requirements, and the existence of needed guidelines and procedures. The Company has established controls, guidelines, procedures, and organizations to support and independently monitor fuel procurement, hedging, and power optimization activities. As noted in items 4 and 5, the Company has a robust oversight culture and processes that include oversight by the TRC, periodic audits by Audit Services, and independent reporting and credit monitoring by Risk Management to ensure adherence to established guidelines and procedures.

Item 9. Verify that the utility has sufficient policies and procedures to implement its strategy.

DEF maintains sufficient guidelines and procedures to implement its strategy. Please see **Attachment K** for a summary listing of the applicable guidelines and procedures.

Item 13. Describe the utilities reporting system for fuel procurement activities.

The Company utilizes multiple systems and applications to track, record, account, and report on executed fuel procurement activities. Descriptions of the primary systems, software, and other tools are provided below.

Forecasted fuel burns are prepared by the Company using a production cost simulation model called GenTrader. Fuel and other commodity price forecasts, load forecasts, purchased power deal information, generating unit operating characteristics, maintenance schedules, and other pertinent data are input into GenTrader which then simulates the system and computes a projected fuel burn requirement

Aligne is a software application used by the Company to capture natural gas physical procurement transactions as well as financial natural gas and light oil transactions. In addition to deal capture, Aligne is used for deal valuation, position management, mark-to-market calculations, and settlements. Aligne is integrated with the Gas Management System (GMS) which is a natural gas scheduling tool used to match supply and deliveries. Once volumes are updated in GMS with actual volumes, there is a process that systematically updates the physical deals in Aligne.

The GMS is a software application used by the Company to match supply, transport, and deliveries for natural gas purchases, sales, and transport activity and the administration of associated contracts. The system is integrated with Aligne as outlined above, which provides for greater efficiency and controls for gas related activities.

Fuelworx is a software application used by the Company to capture and track physical procurement activity for coal and fuel oil. The system assists with administering contract terms and conditions, maintaining inventory levels, capturing fuel consumption information, and issuing monthly closeout processes, including invoicing, and settlements.

Front Office, Risk Management, and Accounting utilize other programs such as Business Objects and Excel to summarize, evaluate, and report on fuel

procurement transactions and counterparty credit evaluations. In addition, Energy Supply Analytics and Risk Management utilize Matlab, a computer programming language, to calculate VAR and run other scenarios as needed by the business units.

Lastly, the Company has agreements with vendors to provide real time pricing feeds to monitor real-time natural gas, fuel oil, and power market prices.

Item 14. **Verify the utility's reporting system and other tools consistently and comprehensively identifies, measures and monitors all forms of risk associated with fuel procurement activities.**

As outlined in the response to item 13, the Company utilizes several applications to ensure procurement and hedging activities are captured, measured, monitored, confirmed, accounted for, and reported. The Company uses standard industry reporting templates, valuation techniques and applications. The current applications utilized by the Company provide the necessary functionality for capturing deals, summarizing fuel positions, calculating mark-to-market valuations, calculating credit and collateral exposures, generating confirmations, supporting billing and payment requirements, and maintaining needed historical information such as prices and trade data.

Item 15. **If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan detailing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.**

DEF does not believe that there are any current limitations to execute its hedging strategy in a reasonable and prudent manner.

ATTACHMENT A

REDACTED

DEF FRANCHISED ELECTRIC RISK LIMITS

(10 pages)

Attachment B

REDACTED

Regulated Fuels Hedging Portfolio

Total Default Exposure (MtM) by commodity

Report Date: 7/11/2013
As of: 7/10/2013

Duke Energy Florida, Inc.

$ in millions

Commodity	2013	2014	2015	2016	201	2018	2019	Total
Gas[A]								
Fixed Price Physical								
Fixed Swaps								
Financial Options								
Oil[B]								
Fixed Swaps No.6								
Financial Options No.6								
Fixed Swaps No.2								
Financial Options No.2								
Coal[D]								
Fixed Priced								
Collar Priced								
Market Priced								
Ammonia[E]								
Fuel Surcharge[F]								
Barge								
Rail								
DEF Total								

Notes:

[redacted]

Prepared by: Global Risk Management

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-1P)
Page 20 of 68

REDACTED

DEF ISDA COLLATERAL SUMMARY

(1 page)

ATTACHMENT C

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-1P)
Page 21 of 68

ATTACHMENT D

REDACTED

DEF AUTHORITY LIMIT MATRIX
(2 pages)

ATTACHMENT E

REDACTED

DEF COMMODITY RISK POLICY

(6 pages)

ATTACHMENT F

REDACTED

DEF CREDIT POLICY

(5 pages)

ATTACHMENT G

REDACTED

DEF FRANCHISED ELECTRIC CREDIT LIMITS
(5 pages)

ATTACHMENT H

REDACTED

DEF ENERGY SUPPLY BULK POWER MARKETING & TRADING DELEGATION OF AUTHORITY

(2 pages)

Attachment I - REDACTED

Duke Energy Corporation
Franchised Electric
Risk Management Control Manual

DUKE ENERGY.

December 2012

REDACTED

Risk Management Controls and Procedures for Fuels & Systems Optimization and Wholesale Power and Renewable Generation

Confidential Information

The information contained within this manual is confidential and proprietary to Duke Energy Corporation's Franchised Electric & Gas group, particularly Fuels & Systems Optimization (FSO) and the Wholesale Power and Renewable Generation (WaR) and the various groups supporting these operations as further defined within this manual. Confidential and proprietary information is a valuable resource. Release of this information to the general public could lead to a competitive disadvantage for Duke Energy Corporation and its subsidiaries ("Duke Energy").

Also, release of this information to the Non-Regulated portions of Duke Energy could result in violation of regulatory rules (FERC Affiliate Restrictions/Standards of Conduct). Confidential and proprietary information must be protected from unauthorized use, modification, disclosure, or destruction whether intentional or unintentional. Duke Energy employees must also comply and acknowledge review of the Code of Business Ethics policy.

REDACTED

Table of Contents:

I. Introduction and Purpose 5
Risk Management Policies and Procedures 5
Control Manual Amendments and Approvals 6
Legal and Regulatory Compliance 6
Exception Process 7
New Employees 8
Inter-Affiliate Transactions 8
II. Concept of Operations 8
Duke Energy Carolinas & Progress Energy Carolinas 9
Progress Energy Florida 9
Duke Energy Indiana & Duke Energy Kentucky 10
Duke Energy Ohio 11
III. Roles and Responsibilities 11
Role of Corporate Officers 11
Segregation of Function and Ownership 12
Role of Chief Risk Officer 12
Role of Corporate Risk Management 12
Role of Fuels & Systems Optimization 13
Role of Traders 14
Role Regulated Fuels 14
Role of Wholesale Power and Renewable Generation 14
Role of Energy Supply Analytics 15
Role of Contract Management 15
Role of Internal Audit 15
Role of Ethics and Compliance 16
Role of Duke Energy General Counsel 16
Role of Accounting 16
Role of Treasury 17

IV. Control Requirements and Activities 17
Risk Management 17
Risk Management - Credit Risk 19
Violations of Risk Control Manual 19
Fuels & Systems Optimization 20
Contract Management 22
V. Dodd-Frank 23

Appendices:

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Appendix A – Key Risks 25
Appendix B – Unauthorized Transactions 27
Appendix C – Confirmations & Settlement Activities 28
Appendix D – New Products/Business Activities Approval Process 30
Appendix E – New Product Checklist 31
Appendix F – Potential Trade Exceptions 32
Appendix G – Potential Deliver Term Violations 33
Appendix H – Employee Acknowledgment 34
Appendix I – FERC 741 Officer Certification Process 36

REDACTED

I. Introduction and Purpose

[redacted]

Risk Management Policies and Procedures

[redacted]

REDACTED

[redacted]

Control Manual Amendments and Approvals

[redacted]

REDACTED

Legal and Regulatory Compliance

[redacted]

Exception Process

[redacted]

REDACTED

[redacted]

New Employees

[redacted]

Inter-Affiliate Transactions

[redacted]

REDACTED

II. Concept of Operations

[redacted]

Carolinas (Duke Energy Carolinas & Progress Energy Carolinas)

[redacted]

REDACTED

Progress Energy Florida

[redacted]

Duke Energy Indiana & Duke Energy Kentucky

[redacted]

REDACTED

[redacted]

Duke Energy Ohio

[redacted]

III. Roles & Responsibilities

Role of Corporate Officers

[redacted]

Segregation of Function and Ownership

[redacted]

Role of the Chief Risk Officer

[redacted]

Role of Corporate Risk Management

[redacted]

REDACTED

Role of Fuels & Systems Optimization

[redacted]

Role of Traders

[redacted]

Role of Regulated Fuels

REDACTED

[redacted]

Role of Wholesale Power and Renewable Generation

[redacted]

Role of Energy Supply Analysis

[redacted]

REDACTED

Role of Contract Management

[redacted]

Role of Internal Audit

[redacted]

Role of Ethics and Compliance

[redacted]

Role of Duke Energy General Counsel

[redacted]

Role of Accounting

[redacted]

REDACTED

[redacted]

Role of Treasury

[redacted]

REDACTED

IV. Control Requirements and Activities

Risk Management

[redacted]

REDACTED

[redacted]

Risk Management – Credit Risk

[redacted]

REDACTED

[redacted]

Violations of Risk Control Manual

[redacted]

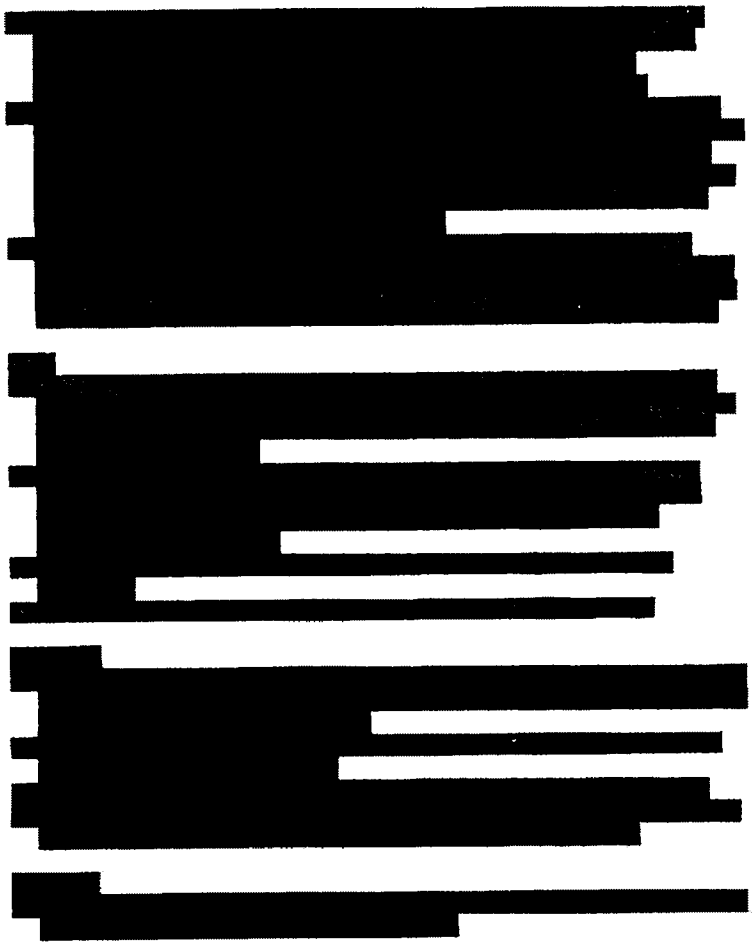
REDACTED

[redacted]

Fuels & Systems Optimization

[redacted]

REDACTED



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Contract Management

REDACTED

V. Dodd-Frank

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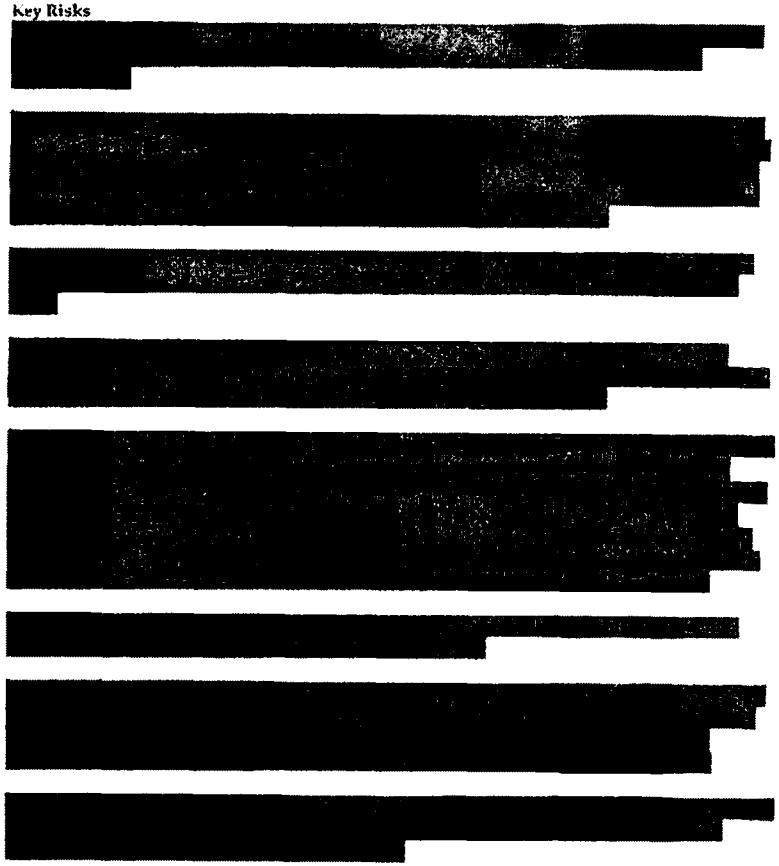
Appendix A

Key Risks



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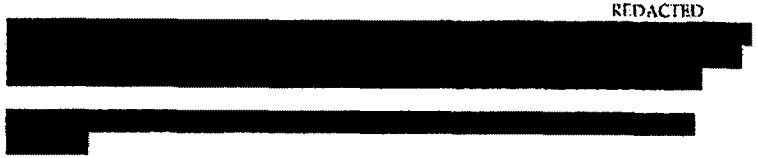


Appendix B

Unauthorized Transactions

[redacted]

Appendix C

Confirmation Activities:

[redacted]

[redacted]

Settlement Activities:

[redacted]

Appendix D

New Products/Business Activity Approval Process

[redacted]

Appendix E

New Product Checklist

[redacted]

Appendix F

Potential Trade Exceptions

[redacted]

Appendix C

Potential Delivery Term Violations

Appendix H

Risk Management Employee Acknowledgment

Employee Name:_____
(Please print)

RISK MANAGEMENT EMPLOYEE ACKNOWLEDGMENT

Corporate **Risk Management** has a combination of Policies, Risk Limits, Guidelines and procedures **referred** to as the "Risk Documents" that contain certain information regarding the governance and procedures of certain Duke Energy activities. Please read and review the appropriate Risk Documents. If you have any questions regarding the Risk Documents, you are to **contact** your immediate supervisor. It is very important that you understand how the Risk Documents apply to your current position. After reading and understanding the appropriate Risk Documents, please check the Risk Documents read and **understood** below and sign the Risk Management Employee Acknowledgment as instructed in the last line below.

Check all that apply:

- Duke Energy Commodity Risk Policy (applies across all entities) ☐
- Duke Energy Credit Policy (applies across all entities) ☐
- Model Review and Approval Process (applies across all entities) ☐
- Dodd-Frank Act Governance Policy (applies across all entities) ☐
- Duke Energy Franchised Electric Risk Management Control Manual ☐
- Duke Energy Carolinas & Progress Energy Carolinas Risk Limits ☐
- Progress Energy Florida Electric Risk Limits ☐
- Duke Energy Indiana Electric Risk Limits ☐
- Duke Energy Kentucky Electric Risk Limits ☐
- Duke Energy Carolinas Credit Limits ☐
- Progress Energy Florida Credit Limits ☐
- Progress Energy Carolinas Credit Limits ☐
- Duke Energy Indiana & Duke Energy Kentucky Credit Limits ☐
- Delegation of Authority – Fuels & Systems Optimization ☐

I have read the Risk Documents as indicated above outlining Duke Energy's expectations of me. I understand and acknowledge these Risk Documents apply to my position. I acknowledge and agree that it is my responsibility to comply with all aspects

of the Risk Documents as well as any future revisions made to the Risk Documents. If I encounter a situation in which I do not know how the Risk Documents applies, I will contact my immediate supervisor.
I further acknowledge and agree that I will contact my immediate supervisor should my responsibilities at Duke Energy change and questions arise regarding the application of the Risk Documents to my new position and/or responsibilities.

I understand and acknowledge that my failure to comply with the Risk Documents will result in corrective action, up to and including termination.

I ACKNOWLEDGE AND UNDERSTAND THAT NEITHER THE RISK DOCUMENTS EMPLOYEE ACKNOWLEDGMENT NOR ANY OF DUKE ENERGY'S POLICIES OR PROCEDURES, INDIVIDUALLY OR TOGETHER, CONSTITUTE A GUARANTEE OF CONTINUED EMPLOYMENT, CREATE A CONTRACT OF EMPLOYMENT OR ALTER THE AT-WILL NATURE OF MY EMPLOYMENT IN ANY WAY.

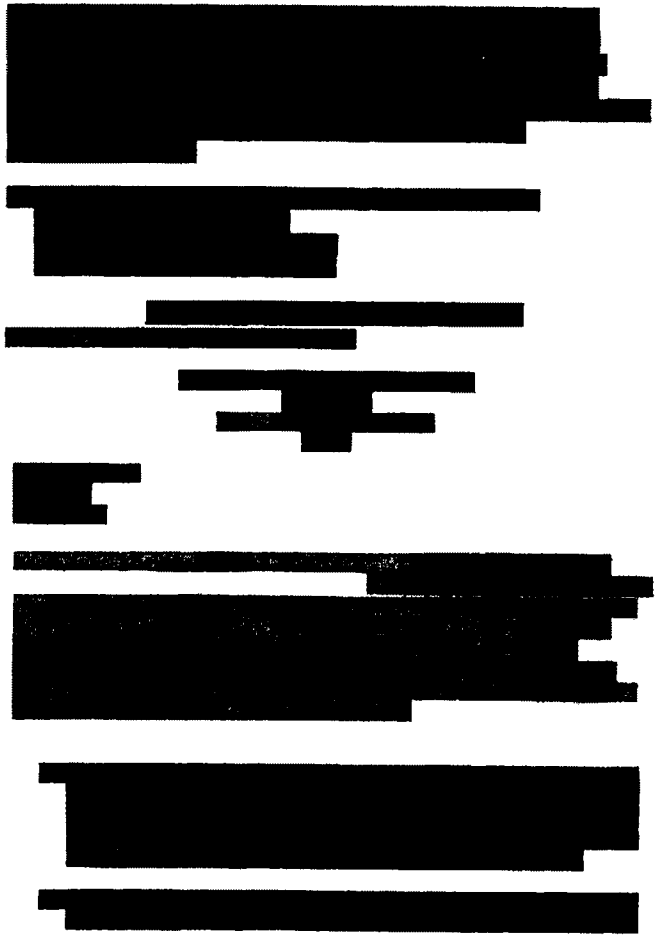
_____ / _____
Employee Signature / Date

_____
Employee Title

_____
Print Full Name

Appendix I

FERC 741 Officer Certification Process



[redacted]

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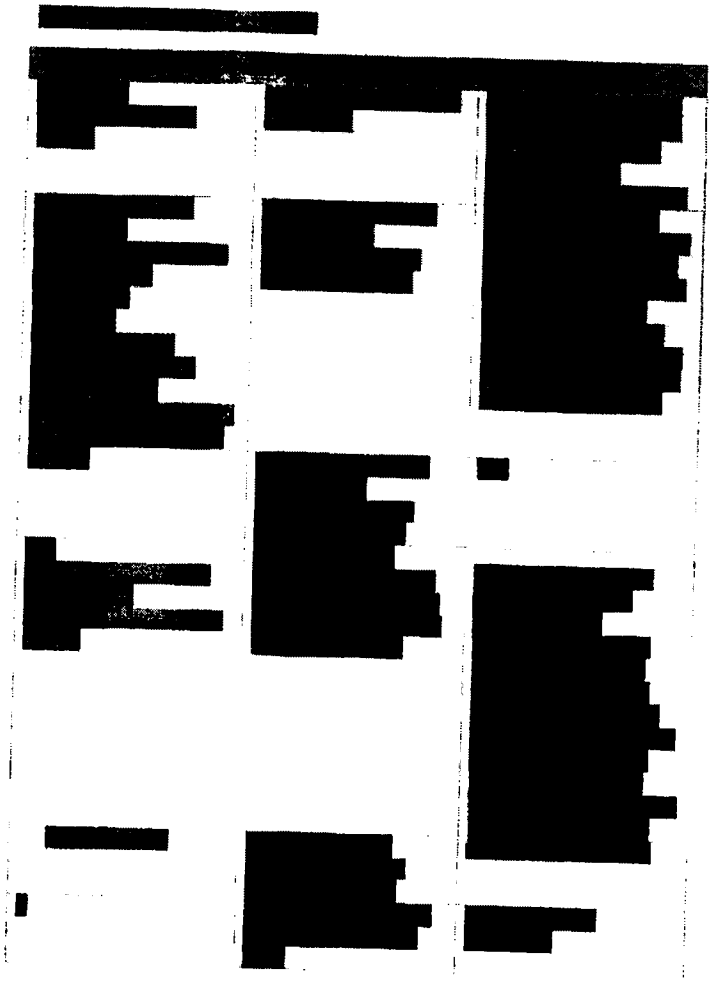

Attachment J

Appendix H

Risk Management Employee Acknowledgment

Employee Name:_____
(Please print)

RISK MANAGEMENT EMPLOYEE ACKNOWLEDGMENT

Corporate Risk Management has a combination of Policies, Risk Limits, Guidelines and procedures referred to as the "Risk Documents" that contain certain information regarding the governance and procedures of certain Duke Energy activities. Please read and review the appropriate Risk Documents. If you have any questions regarding the Risk Documents, you are to contact your immediate supervisor. It is very important that you understand how the Risk Documents apply to your current position. After reading and understanding the appropriate Risk Documents, please check the Risk Documents read and understood below and sign the Risk Management Employee Acknowledgment as instructed in the last line below.

Check all that apply:

- Duke Energy Commodity Risk Policy (applies across all entities) ☐
- Duke Energy Credit Policy (applies across all entities) ☐
- Model Review and Approval Process (applies across all entities) ☐
- Dodd-Frank Act Governance Policy (applies across all entities) ☐
- Duke Energy Franchised Electric Risk Management Control Manual ☐
- Duke Energy Carolinas & Progress Energy Carolinas Risk Limits ☐
- Progress Energy Florida Electric Risk Limits ☐
- Duke Energy Indiana Electric Risk Limits ☐
- Duke Energy Kentucky Electric Risk Limits ☐
- Duke Energy Carolinas Credit Limits ☐
- Progress Energy Florida Credit Limits ☐
- Progress Energy Carolinas Credit Limits ☐
- Duke Energy Indiana & Duke Energy Kentucky Credit Limits ☐
- Delegation of Authority – Fuels & Systems Optimization ☐

I have read the Risk Documents as indicated above outlining Duke Energy's expectations of me. I understand and acknowledge these Risk Documents apply to my position. I acknowledge and agree that it is my responsibility to comply with all aspects

Attachment J

of the Risk Documents as well as any future revisions made to the Risk Documents. If I encounter a situation in which I do not know how the Risk Documents applies, I will contact my immediate supervisor.
I further acknowledge and agree that I will contact my immediate supervisor should my responsibilities at Duke Energy change and questions arise regarding the application of the Risk Documents to my new position and/or responsibilities.

I understand and acknowledge that my failure to comply with the Risk Documents will result in corrective action, up to and including termination.

I ACKNOWLEDGE AND UNDERSTAND THAT NEITHER THE RISK DOCUMENTS EMPLOYEE ACKNOWLEDGMENT NOR ANY OF DUKE ENERGY'S POLICIES OR PROCEDURES, INDIVIDUALLY OR TOGETHER, CONSTITUTE A GUARANTEE OF CONTINUED EMPLOYMENT, CREATE A CONTRACT OF EMPLOYMENT OR ALTER THE AT-WILL NATURE OF MY EMPLOYMENT IN ANY WAY.

_____ /_____
Employee Signature / Date

_____
Employee Title

_____
Print Full Name

FILED AUG 30, 2013
DOCUMENT NO. 05175-13
FPSC - COMMISSION CLERK

EXHIBIT NO. ___ (JM-2P)

REDACTED

"HEDGING RESULTS JANUARY 2013 THROUGH JULY 2013"

(originally filed on August 16, 2013)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 28
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Joesph McCallister - JM-2P

REDACTED

Duke Energy Florida, Inc.
Order No. PSC-08-0316-PAA-EI
Witness: McCallister
Exhibit No. _____

Hedging Instrument	Fuel Type	Total January through July 2013 Volume Hedged		Avg Period of Hedge	Total Cost of Hedge	Total Savings/(Cost) of Hedge
OTC Financial Instruments	Light Oil	[redacted]	barrels	month	[redacted]	
OTC Financial Instruments	Natural Gas		mmbtu's	daily		
OTC Financial Instruments	Natural Gas - Storage		mmbtu's	daily		
OTC Financial Instruments	Light Oil - River Barge		gallons	month		
OTC Financial Instruments	Light Oil - Rail		gallons	month		
						($81,624,728)

Attachment A
DEF "Hedging Summary"
Jan – July 2013 Hedging Data
Page 1 of 1

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. _____ (JM-2P)
Page 2 of 26

Order No. PSC-08-0316-PAA-EI
Duke Energy Florida
Natural Gas and Oil Hedging Detail

REDACTED

Attachment B
DEF "Hedging Details"
Jan – July 2013

Natural Gas

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (MMBtu's): Financial	Physical	Total Hedged	Actual Burn (Generation & Tolling)	Hedged Burns	% Hedged with Financial	% Hedged with Physical	
Jan-13							13,114,500				
Feb-13							11,917,200				
Mar-13							13,740,900				
Apr-13							12,722,600				
May-13							14,957,700				
Jun-13							18,572,900				
Jul-13							19,247,800				See Note 1
YTD	($81,311,053)	$0	($81,311,053)	72,570,000	0	72,570,000	104,273,600	70%	100%	0%	See Note 2

No. 2 Oil

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Barrels): Financial	Physical	Total Hedged	Actual Burn (Generation)	Hedged Burns	% Hedged with Financial	% Hedged with Physical	
Jan-13							9,315				
Feb-13							15,518				
Mar-13							8,432				
Apr-13							11,023				
May-13							13,102				
Jun-13							17,334				
Jul-13							14,893				See Note 1
YTD	($189,361)	$0	($189,361)	30,000	0	30,000	89,617	33%	100%	0%	See Note 2

Natural Gas Storage

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (MMBtu's): Financial	Physical	Total Hedged	Actual Injections	Hedged Injections	% Hedged with Financial	% Hedged with Physical	
Jun-13							250,000				
YTD	$25,575	$0	$25,575	150,000	0	150,000	250,000	60%	100%	0%	See Note 2

Heating Oil - River Barge - Fuel Surcharge Hedges

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Gallons): Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical	
Jan-13							521,349				
Feb-13							528,738				
Mar-13							528,736				
Apr-13							528,738				
May-13							528,738				
Jun-13							530,468				
Jul-13							337,958				
YTD	($111,052)	$0	($111,052)	1,680,000	0	1,680,000	3,504,727	48%	100%	0%	See Note 2

Heating Oil - Rail - Fuel Surcharge Hedges

Year	Savings/(Cost) on Hedges: Financial	Physical	Total	Hedged Volumes (Gallons): Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical	
Jan-13							176,906				
Feb-13							176,477				
Mar-13							176,477				
Apr-13							176,477				
May-13							176,477				
Jun-13							174,082				
Jul-13							174,082				
YTD	($38,837)	$0	($38,837)	714,000	0	714,000	1,230,978	58%	100%	0%	See Note 2

Note 1: Actual burns for periods January 2013 through June 2013. July 2013 burn numbers are considered estimates subject to minor adjustments based on actual bookings

Note 2: Based on actual fuel burns for January 2013 through July 2013, and forecasted fuel burns and estimated fuel surcharge exposures for the balance of 2013, DEF is currently within all of the hedging targets established in the 2013 Risk Management Plan

Hedging Details for "Natural Gas" (Jan – July 2013)

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3272956	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3272956	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3329706	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3329705	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3369594	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3369594	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3455148	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3455148	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3488181	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3488181	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3491465	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3491465	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3502035	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3502035	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3514713	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3514713	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED FINANCIAL OPTION	CALL	1/1/2013	3571186	BAR#	IFERC	TRNSZ4			$3.3800			
Financial	FIXED FINANCIAL OPTION	PUT	1/1/2013	3571186	BAR#	IFERC	TRNSZ4			$3.3800			
Financial	FIXED SWAP		1/1/2013	2209421	DEU#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2244155	MSCG	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2262126	MSCG	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2348605	JPMC#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	237271#	JPMC#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	2625163	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	2640235	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	2656079	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3202228	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3207066	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3213904	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3217519	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3222099	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3226054	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3231885	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3274074	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3285356	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3298000	MACQ#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3301233	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3309048	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3312394	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3321830	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3329693	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3334010	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3341166	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3347573	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3349580	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3353527	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3355367	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3367374	CEH#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3371630	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3371671	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3372243	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3373620	MACQ#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3377742	MSCG	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3379138	JPMC#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3383970	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3386626	MACQ#	NYMEX	NG			$3.3540			

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 2 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. _____ (JM-2P)
Page 5 of 26

DEF Gas Hedging Status REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		1/1/2013	3305983	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3446436	CSEL	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3450972	CITI#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3461248	BAR#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3472650	BAR#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3478078	CEH#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3479624	DEU#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3490398	CEH#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3502916	BOM#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3508828	DEU#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3516194	BOM#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3522742	SG#	NYMEX	NG			$3.3540			
Financial	FIXED SWAP		1/1/2013	3526028	CEH#	IFERC	HHUB			$3.3500			
Financial	FIXED SWAP		1/1/2013	3534316	CEH#	IFERC	HHUB			$3.3500			
												13,114,500	69%

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 6 of 26

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 3 of 19

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3272957	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3272957	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3329707	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3329707	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3369597	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3369597	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3455149	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3455149	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3488182	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3488182	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3491466	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3491466	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3502036	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3502036	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3514714	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3514714	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED FINANCIAL OPTION	CALL	2/1/2013	3571187	BAR#	IFERC	TRNSZ4			$3.2400			
Financial	FIXED FINANCIAL OPTION	PUT	2/1/2013	3571187	BAR#	IFERC	TRNSZ4			$3.2400			
Financial	FIXED SWAP		2/1/2013	2209422	DEU#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2244151	MSCG	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2262127	MSCG	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2348610	JPMC#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2372719	JPMC#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	2625164	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	2640236	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	2656090	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3202229	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3207067	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3213905	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3217520	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3222400	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3225085	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3231886	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3274075	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3295357	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3298001	MACQ#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3301234	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3309049	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3312395	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3321931	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3329694	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3334011	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3341167	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3347574	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3349581	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3353528	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3355368	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3367375	CEH#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3371631	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3371672	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3372244	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3373821	MACQ#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3377743	MSCG	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3379139	JPMC#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3383971	CSEL	NYMEX	NG			$3.2260			

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 7 of 26

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 4 of 19

DEF Gas Hedging Status REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		2/1/2013	3386627	MACQ#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3395984	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3448437	CSEL	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3456973	CITI#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3461249	BAR#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3472651	BAR#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3476079	CEH#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3479625	DEU#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3490399	CEH#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3502917	BOM#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3508829	DEU#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3514195	BOM#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3522743	SG#	NYMEX	NG			$3.2260			
Financial	FIXED SWAP		2/1/2013	3526029	CEH#	IFERC	HHUB			$3.2300			
Financial	FIXED SWAP		2/1/2013	3534317	CEH#	IFERC	HHUB			$3.2300			
												11,917,200	69%

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 5 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. _____ (JM-2P)
Page 8 of 26

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3272958	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3272958	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3329708	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3329708	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3369598	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3369598	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3455150	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3455150	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3488183	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3488183	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3491467	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3491467	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3502037	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3502037	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3514715	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3514715	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED FINANCIAL OPTION	CALL	3/1/2013	3571188	BAR#	IFERC	TRNSZ4			$3.4400			
Financial	FIXED FINANCIAL OPTION	PUT	3/1/2013	3571188	BAR#	IFERC	TRNSZ4			$3.4400			
Financial	FIXED SWAP		3/1/2013	2209423	DEU#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2244152	MSCG	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2262128	MSCG	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2348611	JPMC#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2372722	JPMC#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	2625165	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	2640237	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	2656081	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3202230	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3207068	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3213906	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3217521	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3222401	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3225056	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3231887	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3274076	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3295358	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3298002	MACQ#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3301235	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3309050	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3312396	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3321932	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3329695	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3334012	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3341168	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3347575	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3349582	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3353529	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3355369	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3367376	CEH#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3371632	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3371670	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3372245	CITI#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3373822	MACQ#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3377744	MSCG	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3379140	JPMC#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3383972	CSEL	NYMEX	NG			$3.4270			

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 6 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. _____ (JM-2P)
Page 9 of 26

DEF Gas Hedging Status REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		3/1/2013	3386628	MACQ#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3395985	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3448438	CSEL	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3456974	CIT#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3461250	BAR#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3472652	BAR#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3478080	CEH#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3479626	DEU#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3490402	CEH#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3502918	BOM#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3508830	DEU#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3514196	BOM#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3522744	SG#	NYMEX	NG			$3.4270			
Financial	FIXED SWAP		3/1/2013	3526030	CEH#	IFERC	HHUB			$3.4300			
Financial	FIXED SWAP		3/1/2013	3534318	CEH#	IFERC	HHUB			$3.4300			
												13,740,900	66%

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ___ (JM-2P)
Page 10 of 26

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 7 of 19

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3272959	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3272959	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3329709	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3329709	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3309599	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3309599	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3455151	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3455151	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3488184	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3488184	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3491456	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3491456	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3502038	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3502038	MSCG	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3514716	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3514716	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3571189	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3571189	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3584202	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3584202	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3823744	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3823744	BAR#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	CALL	4/1/2013	3860088	JPMC#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED FINANCIAL OPTION	PUT	4/1/2013	3860088	JPMC#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	2126529	JPMC#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2139415	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2140270	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2165078	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2181888	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2194798	MLC	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2209424	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2220225	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2244153	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2262132	MSCG	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2287617	CSEL	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2299914	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2304860	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2334863	CSEL	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2348612	JPMC#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2372723	JPMC#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2407829	DEU#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2451040	BAR#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2469665	CSEL	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2579397	BAR#	IFERC	HHUB			$3.9800			
Financial	FIXED SWAP		4/1/2013	2622814	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	2655321	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3161160	CITI#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3172596	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3203152	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3220882	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3223690	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3225045	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3277225	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3295359	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3301236	BAR#	NYMEX	NG			$3.9760			

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 8 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 11 of 26

DEF Gas Hedging Status REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		4/1/2013	3309825	CITI#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3334607	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3341169	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3347061	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3371535	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3394493	JPMC#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3477373	CITI#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3490468	CSEL	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3500329	CITI#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3503785	BAR#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3514205	CSEL	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3521382	CITI#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3531923	CITI#	IFERC	MAINLN			$3.9500			
Financial	FIXED SWAP		4/1/2013	3541880	BAR#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3581792	JPMC#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3608565	DEU#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3640046	BPEC	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3667235	MSCG	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3681681	CEH#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3696841	CEH#	IFERC	TRNSZ4			$4.0000			
Financial	FIXED SWAP		4/1/2013	3762627	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3778389	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3780732	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3785888	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3786475	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3788055	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3801713	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3804746	CEH#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3806227	DEU#	NYMEX	NG			$3.9760			
Financial	FIXED SWAP		4/1/2013	3809620	CEH#	NYMEX	NG			$3.9760			
												12,722,500	73%

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3272960	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3272960	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3329710	CSEL	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3329710	CSEL	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3369600	JPMC#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3369600	JPMC#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3455152	MSCG	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3455152	MSCG	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3488185	CSEL	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3488185	CSEL	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3491469	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3491469	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3502039	MSCG	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3502039	MSCG	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3514717	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3514717	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3571190	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3571190	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3584203	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3584203	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3623745	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3623745	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	5/1/2013	3660089	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	5/1/2013	3660089	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	2126530	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2135416	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2140273	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2165079	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2181889	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2194799	MLC	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2209425	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2220226	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2244154	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2262133	MSCG	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2287618	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2298915	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2304861	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2334864	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2348613	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2372724	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2407830	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2451041	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2469666	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2579398	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	2622815	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	2655322	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3161161	CITI#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3172597	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3203153	CSEL	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3220883	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3223661	JPMC#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3225046	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3277229	JPMC#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3295360	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3301237	BAR#	NYMEX	NG			$4.1520			

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 10 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 13 of 26

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		5/1/2013	3304826	CITI#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3334608	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3341170	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3347062	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3350077	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3353485	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3355370	CSEL	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3368710	DEU#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3371636	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3372246	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3377902	CITI#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3384407	JPMC#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3385619	CITI#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3394494	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3458817	BAR#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3473251	CITI#	IFERC	HHUB			$4.1700			
Financial	FIXED SWAP		5/1/2013	3477374	CITI#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3490469	CSEL	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3500330	CITI#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3503788	BAR#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3514206	CSEL	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3521383	CITI#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3531924	CITI#	IFERC	MAINLN			$4.1200			
Financial	FIXED SWAP		5/1/2013	3541881	BAR#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3561793	JPMC#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3608566	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3640047	BPEC	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3667236	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3681694	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3696842	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3704585	MACQ#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3743525	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3749645	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3749672	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3751096	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		5/1/2013	3762826	CEH#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3778390	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3780733	CEH#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3785889	CEH#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3788476	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3788056	CEH#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3801714	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3804747	CEH#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3808226	DEU#	NYMEX	NG			$4.1520			
Financial	FIXED SWAP		5/1/2013	3809621	CEH#	NYMEX	NG			$4.1520			
												14,957,700	80%

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3272961	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3272961	BAR#	NYMEX	NG			$4.1450			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3329711	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3329711	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3369601	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3369601	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3455153	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3455153	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3488186	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3488186	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3491470	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3491470	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3502040	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3502040	MSCG	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3514718	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3514718	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3571191	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3571191	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3584204	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3584204	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3623746	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3623746	BAR#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	CALL	6/1/2013	3660090	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED FINANCIAL OPTION	PUT	6/1/2013	3660090	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	2126531	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2130421	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2140274	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2165082	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2181890	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2194600	MLC	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2209426	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2220227	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2244155	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2262136	MSCG	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2287619	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2298916	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2304862	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2334865	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2348614	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2372725	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2407831	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2451044	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2469689	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2579399	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	2622816	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	2655323	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3161162	CITI#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3172598	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3203154	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3220884	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3223062	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3225047	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3277230	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3295361	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3301238	BAR#	NYMEX	NG			$4.1480			

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 12 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 15 of 26

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		6/1/2013	3309827	CITI#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3334809	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3341171	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3347063	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3350080	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3353466	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3355371	CSEL	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3368711	DEU#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3371697	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3372247	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3377903	CITI#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3384408	JPMC#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3386620	CITI#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3394495	JPMC#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3458818	BAR#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3473252	CITI#	IFERC	HHUB			$4.1500			
Financial	FIXED SWAP		6/1/2013	3477375	CITI#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3490470	CSEL	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3500331	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3503789	BAR#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3514207	CSEL	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3521384	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3531926	CITI#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3541882	BAR#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3561794	JPMC#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3608567	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3640048	BPEC	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3667237	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3681700	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3696843	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3704586	MACQ#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3743526	DEU#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3749646	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3749673	MSCG	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3751097	CEH#	IFERC	TRNSZ4			$4.1800			
Financial	FIXED SWAP		6/1/2013	3762529	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3778391	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3780734	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3785890	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3786477	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3788057	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3801715	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3804750	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3805229	DEU#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3809822	CEH#	NYMEX	NG			$4.1480			
Financial	FIXED SWAP		6/1/2013	3830732	CSEL	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3850030	MACQ#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3857445	MACQ#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3859785	MACQ#	IFERC	MAINLN			$4.1000			
Financial	FIXED SWAP		6/1/2013	3864907	CITI#	IFERC	MAINLN			$4.1000			
												18,572,900	66%

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 13 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 16 of 26

DEF Gas Hedging Status REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3272962	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3272962	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3329712	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3329712	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3369602	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3369602	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3455154	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3455154	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3488187	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3488187	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3491471	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3491471	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3502041	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3502041	MSCG	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3514719	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3514719	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3571192	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3571192	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3584205	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3584205	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3623747	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3623747	BAR#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	CALL	7/1/2013	3660091	JPMC#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED FINANCIAL OPTION	PUT	7/1/2013	3660091	JPMC#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	2126532	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2130422	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2140353	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2165083	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2181891	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2194801	MLC	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2209427	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2220228	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2244156	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2262136	MSCG	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2287620	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2298917	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2304863	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2334886	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2348915	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2372726	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2407832	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2451045	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2469670	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	2579400	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3622817	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	2655324	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3161163	CITI#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3172599	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3203155	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3220685	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3223665	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3225048	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3277231	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3295362	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3301239	BAR#	NYMEX	NG			$3.7070			

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 14 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ___ (JM-2P)
Page 17 of 26

DEF Gas Hedging Status

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Put/Call	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP		7/1/2013	3309828	CITI#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3334610	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3341172	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3347004	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3350081	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3353487	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3355372	CSEL	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3358712	DEU#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3371838	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3372248	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3377004	CITI#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3384409	JPMC#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3386821	CITI#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3394496	JPMC#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3458810	BAR#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3473253	CITI#	IFERC	HHUB			$3.7100			
Financial	FIXED SWAP		7/1/2013	3477076	CITI#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3490471	CSEL	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3500332	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3503790	BAR#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3514208	CSEL	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3521385	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3531928	CITI#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3541883	BAR#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3561795	JPMC#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3608568	DEU#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3640049	BPEC	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3667238	MSCG	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3681701	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3696844	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3704591	MACQ#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3743527	DEU#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3749647	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3749674	MSCG	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3751098	CEH#	IFERC	TRNSZ4			$3.7300			
Financial	FIXED SWAP		7/1/2013	3762030	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3778362	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3780735	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3785891	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3786478	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3788058	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3801716	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3804751	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3808230	DEU#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3809623	CEH#	NYMEX	NG			$3.7070			
Financial	FIXED SWAP		7/1/2013	3830733	CSEL	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3856031	MACQ#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3857446	MACQ#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3859786	MACQ#	IFERC	MAINLN			$3.6500			
Financial	FIXED SWAP		7/1/2013	3864906	CITI#	IFERC	MAINLN			$3.6500			
												19,247,600	66%

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 15 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 18 of 26

Hedging Details for "No. #2 Oil" (Jan – July 2013)

DEF #2 Oil Hedging Status

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As of August 6, 2013

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume (Bbls)	Fixed Price ($/Bbl)	Market Scan Biz Average ($/Bbl)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	1/1/2013	3532485	BOM#	USGLF	NO2ULS			$128.06			
											9,315	32%
Financial	FIXED SWAP	2/1/2013	3532486	BOM#	USGLF	NO2ULS			$134.7402			
											15,518	19%
Financial	FIXED SWAP	3/1/2013	3532489	BOM#	USGLF	NO2ULS			$126.4494			
											8,432	36%
Financial	FIXED SWAP	4/1/2013	3532491	BOM#	USGLF	NO2ULS			$120.8046			
Financial	FIXED SWAP	4/1/2013	3748949	DEU#	USGLF	NO2ULS			$120.8046			
											11,023	36%
Financial	FIXED SWAP	5/1/2013	3532493	BOM#	USGLF	NO2ULS			$119.3724			
Financial	FIXED SWAP	5/1/2013	3748956	DEU#	USGLF	NO2ULS			$119.3724			
Financial	FIXED SWAP	5/1/2013	3937694	BOM#	USGLF	NO2ULS			$119.3724			
											13,102	61%
Financial	FIXED SWAP	6/1/2013	3532495	BOM#	USGLF	NO2ULS			$120.1242			
Financial	FIXED SWAP	6/1/2013	3748958	DEU#	USGLF	NO2ULS			$120.1242			
											17,334	23%
Financial	FIXED SWAP	7/1/2013	3544358	MACQ#	USGLF	NO2ULS			$125.2902			
Financial	FIXED SWAP	7/1/2013	3599953	JPMC#	USGLF	NO2ULS			$125.2902			
Financial	FIXED SWAP	7/1/2013	3674000	JPMC#	USGLF	NO2ULS			$125.2902			
Financial	FIXED SWAP	7/1/2013	3748960	DEU#	USGLF	NO2ULS			$125.2902			
											14,893	34%

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 16 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ___ (JM-2P)
Page 20 of 26

Hedging Details for "Gas Storage" (Jan – July 2013)

DEF Gas Storage Hedging REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Month	Z Key	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual Injection	% Hedged
Financial	FIXED SWAP	6/1/2013	3966424	CSEL	IFERC	FGTZ3			$4.2600			
Financial	FIXED SWAP	6/1/2013	3971356	MACQ#	IFERC	FGTZ3			$4.2600			
											250,000	60%

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 17 of 19

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 22 of 26

Hedging Details for "Coal Transportation – River Barge" (Jan – July 2013)

DEF Coal Transportation Hedging Status - Barge

REDACTED

As of August 6, 2013

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2013	3521823	USGLF	NO2ULS			$3.0496			
Financial	FIXED SWAP	1/1/2013	3736415	USGLF	NO2ULS			$3.0496			
Financial	FIXED SWAP	1/1/2013	3761003	USGLF	NO2ULS			$3.0496			
Financial	FIXED SWAP	1/1/2013	3801025	USGLF	NO2ULS			$3.0496			
										521,349	48%
Financial	FIXED SWAP	2/1/2013	3521824	USGLF	NO2ULS			$3.2081			
Financial	FIXED SWAP	2/1/2013	3736417	USGLF	NO2ULS			$3.2081			
Financial	FIXED SWAP	2/1/2013	3761005	USGLF	NO2ULS			$3.2081			
Financial	FIXED SWAP	2/1/2013	3801027	USGLF	NO2ULS			$3.2081			
										528,738	48%
Financial	FIXED SWAP	3/1/2013	3521825	USGLF	NO2ULS			$3.0107			
Financial	FIXED SWAP	3/1/2013	3736419	USGLF	NO2ULS			$3.0107			
Financial	FIXED SWAP	3/1/2013	3761007	USGLF	NO2ULS			$3.0107			
Financial	FIXED SWAP	3/1/2013	3801029	USGLF	NO2ULS			$3.0107			
										528,738	48%
Financial	FIXED SWAP	4/1/2013	3540872	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3711714	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3776782	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3803835	USGLF	NO2ULS			$2.8763			
										528,738	48%
Financial	FIXED SWAP	5/1/2013	3540873	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3711716	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3776784	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3803837	USGLF	NO2ULS			$2.8422			
										528,738	48%
Financial	FIXED SWAP	6/1/2013	3540875	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3711718	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3776786	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3803839	USGLF	NO2ULS			$2.8601			
										530,468	48%
Financial	FIXED SWAP	7/1/2013	3544398	USGLF	NO2ULS			$2.9831			
Financial	FIXED SWAP	7/1/2013	3599947	USGLF	NO2ULS			$2.9831			
Financial	FIXED SWAP	7/1/2013	3714481	USGLF	NO2ULS			$2.9831			
										337,968	50%

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 24 of 26

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 18 of 19

Hedging Details for "Coal Transportation - Rail" (Jan – July 2013)

DEF Coal Transportation Hedging Status - Rail

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As of August 6, 2013

Physical/ Financial	Instrument	Month	Z Key	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2013	3521797	USGLF	NO2ULS			$3.0496			
										176,906	47%
Financial	FIXED SWAP	2/1/2013	3521798	USGLF	NO2ULS			$3.2081			
										176,477	48%
Financial	FIXED SWAP	3/1/2013	3521799	USGLF	NO2ULS			$3.0107			
										176,477	48%
Financial	FIXED SWAP	4/1/2013	3540866	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3711704	USGLF	NO2ULS			$2.8763			
Financial	FIXED SWAP	4/1/2013	3751199	USGLF	NO2ULS			$2.8763			
										176,477	71%
Financial	FIXED SWAP	5/1/2013	3540867	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3711706	USGLF	NO2ULS			$2.8422			
Financial	FIXED SWAP	5/1/2013	3751200	USGLF	NO2ULS			$2.8422			
										176,477	71%
Financial	FIXED SWAP	6/1/2013	3540868	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3711708	USGLF	NO2ULS			$2.8601			
Financial	FIXED SWAP	6/1/2013	3751203	USGLF	NO2ULS			$2.8601			
										174,082	72%
Financial	FIXED SWAP	7/1/2013	3599941	USGLF	NO2ULS			$2.9831			
Financial	FIXED SWAP	7/1/2013	3764916	USGLF	NO2ULS			$2.9831			
										174,082	48%

Docket No. 130001-EI
Duke Energy Florida
Exhibit No. ____ (JM-2P)
Page 26 of 26

Attachment B
DEF "Hedging Details"
Jan – July 2013
Page 19 of 19

Progress Energy Florida
Docket No. 130001-EI
Witness: JONES
Exhibit No. _____ (MJJ-1T)

GPIF REWARD/PENALTY SCHEDULES

Description	Sheet
Index	1
Reward/Penalty Table (Actual)	2
Calculation of Maximum Incentive Dollars (Actual)	3
Calculation of System Actual GPIF Points	4
GPIF Unit Performance Summary	5
Actual Unit Performance Data	6
Adjustments to EAF Actual	7
Adjustments to ANOHR Actual	8
Generating Performance Incentive Points Table	9-15
Actual Unit Performance Data	16-22
Planned Outage Schedules (Actual)	23-24

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 29
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Matthew Jones - MJJ-1T

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Progress Energy Florida
Janauary 2012 - December 2012

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$ 79,804,324	$ 19,304,422
	9	$ 71,823,892	$ 17,373,980
	8	$ 63,843,460	$ 15,443,538
	7	$ 55,863,027	$ 13,513,095
	6	$ 47,882,595	$ 11,582,653
	5	$ 39,902,162	$ 9,652,211
	4	$ 31,921,730	$ 7,721,769
	3	$ 23,941,297	$ 5,791,327
	2	$ 15,960,865	$ 3,860,884
****	1.69	$ 13,486,931	$ 3,262,447
	1	$ 7,980,432	$ 1,930,442
	0	$ -	$ -
	-1	$ (11,952,622)	$ (1,930,442)
	-2	$ (23,905,245)	$ (3,860,884)
	-3	$ (35,857,867)	$ (5,791,327)
	-4	$ (47,810,490)	$ (7,721,769)
	-5	$ (59,763,112)	$ (9,652,211)
	-6	$ (71,715,735)	$ (11,582,653)
	-7	$ (83,668,357)	$ (13,513,095)
	-8	$ (95,620,980)	$ (15,443,538)
	-9	$ (107,573,602)	$ (17,373,980)
	-10	$ (119,526,224)	$ (19,304,422)

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Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Progress Energy Florida
Janauary 2012 - December 2012

1	Beginning of period balance of common equity	$ 4,675,729,898
	END OF MONTH BALANCE OF COMMON EQUITY:	
2	Month of JANUARY 2012	$ 4,666,822,518
3	Month of FEBRUARY 2012	$ 4,686,866,036
4	Month of MARCH 2012	$ 4,700,479,231
5	Month of APRIL 2012	$ 4,727,101,371
6	Month of MAY 2012	$ 4,774,463,238
7	Month of JUNE 2012	$ 4,718,599,619
8	Month of JULY 2012	$ 4,772,849,792
9	Month of AUGUST 2012	$ 4,833,485,375
10	Month of SEPTEMBER 2012	$ 4,845,271,950
11	Month of OCTOBER 2012	$ 4,879,340,920
12	Month of NOVEMBER 2012	$ 4,892,719,880
13	Month of DECEMBER 2012	$ 4,901,512,384
14	Average common equity for the period	$ 4,775,018,632
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	61.3808%
17	Maximum allowed incentive dollars	$ 19,448,340
18	Jurisdictional Sales *	36,381,457 MWH
19	Total Sales *	36,653,335 MWH
20	Jurisdictional Separation Factor	99.2600%
21	Maximum allowed jurisdictional incentive dollars	$ 19,304,422

* Net sales (Sales - Interruptible)

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Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Progress Energy Florida
Janauary 2012 - December 2012

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Bartow CC	EAF	9.63	10.000	0.963
	ANOHR	18.97	-3.867	-0.734
Crystal River 4	EAF	9.38	8.034	0.753
	ANOHR	12.29	0.000	0.000
Crystal River 5	EAF	5.54	4.712	0.261
	ANOHR	10.36	-4.257	-0.441
Hines 1	EAF	3.12	6.890	0.215
	ANOHR	4.47	-2.324	-0.104
Hines 2	EAF	2.93	10.000	0.293
	ANOHR	5.60	0.000	0.000
Hines 3	EAF	1.97	10.000	0.197
	ANOHR	6.48	-1.189	-0.077
Hines 4	EAF	2.60	10.000	0.260
	ANOHR	6.67	1.561	0.104
GPIF System		100.00		1.690

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Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Progress Energy Florida
Janauary 2012 - December 2012

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
Bartow CC	9.63	81.81	85.95	73.42	$7,684	($22,307)	88.04	$7,684
Crystal River 4	9.38	90.50	94.92	81.71	$7,483	($21,288)	94.05	$6,012
Crystal River 5	5.54	85.12	87.62	80.06	$4,419	($8,549)	86.30	$2,082
Hines 1	3.12	84.31	87.29	78.37	$2,488	($5,132)	86.37	$1,714
Hines 2	2.93	86.26	88.74	81.17	$2,335	($4,371)	91.39	$2,335
Hines 3	1.97	79.62	80.98	76.79	$1,575	($2,748)	82.21	$1,575
Hines 4	2.60	82.61	84.69	78.32	$2,076	($3,387)	86.23	$2,076
GPIF System	35.16				$28,060.1	($67,782.0)		$23,478.3

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
Bartow CC	18.97	7,428	68.0	6,999	7,856	$15,143	($15,143)	7,640	($5,856)
Crystal River 4	12.29	9,947	83.5	9,334	10,560	$9,808	($9,808)	9,994	$0
Crystal River 5	10.36	9,937	88.5	9,407	10,467	$8,265	($8,265)	10,206	($3,518)
Hines 1	4.47	7,291	83.6	7,054	7,528	$3,565	($3,565)	7,403	($829)
Hines 2	5.60	7,158	79.0	6,885	7,431	$4,467	($4,467)	7,136	$0
Hines 3	6.48	7,167	88.4	6,856	7,477	$5,171	($5,171)	7,270	($615)
Hines 4	6.67	6,961	88.7	6,658	7,263	$5,325	($5,325)	6,850	$831
GPIF System	64.84					$51,744.2	($51,744.2)		($9,986.1)

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida
Janauary 2012 - December 2012

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Bartow CC	86.37	1.67	88.04
Crystal River 4	94.05	0.00	94.05
Crystal River 5	78.40	7.90	86.30
Hines 1	88.50	-2.13	86.37
Hines 2	93.43	-2.04	91.39
Hines 3	79.56	2.65	82.21
Hines 4	86.60	-0.37	86.23

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Bartow CC	7,552.4	87.1	7,639.5
Crystal River 4	10,502.6	-509.1	9,993.5
Crystal River 5	10,669.4	-463.6	10,205.8
Hines 1	7,353.0	50.3	7,403.4
Hines 2	7,116.9	18.7	7,135.5
Hines 3	7,297.1	-27.5	7,269.5
Hines 4	6,848.4	1.9	6,850.3

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

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Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Progress Energy Florida
Janauary 2012 - December 2012

	EAF adjustments for Planned Outage Hours		Bartow CC BA4	Crystal River 4 CR4	Crystal River 5 CR5	Hines 1 HN1	Hines 2 HN2	Hines 3 HN3	Hines 4 HN4
1	Actual POH	Hrs.	972.79	0.00	1,567.55	619.38	564.58	1,769.96	1,107.45
2	Target POH	Hrs.	822.00	0.00	840.00	816.00	744.00	1,536.00	1,140.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.02	1.00	1.10	0.98	0.98	1.03	1.00
4	Actual EUOH	Hrs.	224.57	522.47	330.22	390.99	12.52	25.60	70.00
5	Adj. EUOH (3*4)	Hrs.	228.91	522.47	363.52	381.58	12.25	26.45	69.70
6	Actual EAF	%	86.37	94.05	78.40	88.50	93.43	79.56	86.60
7	Adjusted EAF (using 2 & 5)	%	88.04	94.05	86.30	86.37	91.39	82.21	86.23
8	Difference (7-6)	%	1.67	0.00	7.90	-2.13	-2.04	2.65	-0.37
9	Total adj. to EAF	%	1.67	0.00	7.90	-2.13	-2.04	2.65	-0.37

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Progress Energy Florida
Janauary 2012 - December 2012

ANOHR adjustments for Target NOF			Bartow CC BA4	Crystal River 4 CR4	Crystal River 5 CR5	Hines 1 HN1	Hines 2 HN2	Hines 3 HN3	Hines 4 HN4
1	Target NOF	%	68.0	83.5	88.5	83.6	79.0	88.4	88.7
2	Target ANOHR	Btu/kwh	7427.9	9946.9	9937.0	7290.8	7158.4	7166.5	6960.8
3	Actual NOF	%	84.0	72.1	65.9	91.6	86.9	86.7	88.9
4	Calc. ANOHR (using 3)	Btu/kwh	7,340.8	10,456.0	10,400.6	7,240.4	7,139.7	7,194.1	6,958.9
5	Total adj. to ANOHR (2-4)	Btu/kwh	87.1	-509.1	-463.6	50.3	18.7	-27.5	1.9

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Bartow CC

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$7,684,000	85.95	10	$15,142,743	6,999.5	
	10	$7,684,000	85.95	9	$13,628,469	7,034.8	
	9	$6,915,600	85.53	8	$12,114,195	7,070.2	
	8	$6,147,200	85.12	7	$10,599,920	7,105.5	
	7	$5,378,800	84.70	6	$9,085,646	7,140.8	
	6	$4,610,400	84.29	5	$7,571,372	7,176.2	
	5	$3,842,000	83.88	4	$6,057,097	7,211.5	
	4	$3,073,600	83.46	3	$4,542,823	7,246.9	
	3	$2,305,200	83.05	2	$3,028,549	7,282.2	
	2	$1,536,800	82.63	1	$1,514,274	7,317.5	
	1	$768,400	82.22	0	$0	7,352.9	
		$0	81.81	0	$0	7,427.9	
	0	$0	81.81	0	$0	7,502.9	
		$0	81.81	-1	($1,514,274)	7,538.2	
	-1	($2,230,670)	80.97	-2	($3,028,549)	7,573.5	
	-2	($4,461,340)	80.13	-3	($4,542,823)	7,608.9	
	-3	($6,692,010)	79.29	-3.867	($5,855,699)	7,639.5	****
	-4	($8,922,680)	78.45	-4	($6,057,097)	7,644.2	
	-5	($11,153,350)	77.61	-5	($7,571,372)	7,679.6	
	-6	($13,384,020)	76.77	-6	($9,085,646)	7,714.9	
	-7	($15,614,690)	75.93	-7	($10,599,920)	7,750.2	
	-8	($17,845,360)	75.09	-8	($12,114,195)	7,785.6	
	-9	($20,076,030)	74.26	-9	($13,628,469)	7,820.9	
	-10	($22,306,700)	73.42	-10	($15,142,743)	7,856.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
9.63%	18.97%

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Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$7,483,100	94.92	10	$9,808,282	9,333.7	
	9	$6,734,790	94.48	9	$8,827,454	9,387.5	
****	8.034	$6,011,923	94.05	8	$7,846,625	9,441.4	
	8	$5,986,480	94.04	7	$6,865,797	9,495.2	
	7	$5,238,170	93.59	6	$5,884,969	9,549.0	
	6	$4,489,860	93.15	5	$4,904,141	9,602.8	
	5	$3,741,550	92.71	4	$3,923,313	9,656.6	
	4	$2,993,240	92.27	3	$2,942,485	9,710.5	
	3	$2,244,930	91.83	2	$1,961,656	9,764.3	
	2	$1,496,620	91.38	1	$980,828	9,818.1	
	1	$748,310	90.94	0	$0	9,871.9	
		$0	90.50	0	$0	9,946.9	
	0	$0	90.50	0.000	$0	9,993.5	****
		$0	90.50	0	$0	10,021.9	
	-1	($2,128,820)	89.62	-1	($980,828)	10,075.7	
	-2	($4,257,640)	88.74	-2	($1,961,656)	10,129.6	
	-3	($6,386,460)	87.86	-3	($2,942,485)	10,183.4	
	-4	($8,515,280)	86.98	-4	($3,923,313)	10,237.2	
	-5	($10,644,100)	86.10	-5	($4,904,141)	10,291.0	
	-6	($12,772,920)	85.22	-6	($5,884,969)	10,344.9	
	-7	($14,901,740)	84.35	-7	($6,865,797)	10,398.7	
	-8	($17,030,560)	83.47	-8	($7,846,625)	10,452.5	
	-9	($19,159,380)	82.59	-9	($8,827,454)	10,506.3	
	-10	($21,288,200)	81.71	-10	($9,808,282)	10,560.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
9.38%	12.29%

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Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$4,419,000	87.62	10	$8,264,649	9,406.6	
	9	$3,977,100	87.37	9	$7,438,185	9,452.2	
	8	$3,535,200	87.12	8	$6,611,720	9,497.7	
	7	$3,093,300	86.87	7	$5,785,255	9,543.2	
	6	$2,651,400	86.62	6	$4,958,790	9,588.8	
	5	$2,209,500	86.37	5	$4,132,325	9,634.3	
****	4.712	$2,082,233	86.30	4	$3,305,860	9,679.8	
	4	$1,767,600	86.12	3	$2,479,395	9,725.4	
	3	$1,325,700	85.87	2	$1,652,930	9,770.9	
	2	$883,800	85.62	1	$826,465	9,816.5	
	1	$441,900	85.37	0	$0	9,862.0	
		$0	85.12	0	$0	9,937.0	
	0	$0	85.12	0	$0	10,012.0	
		$0	85.12	-1	($826,465)	10,057.5	
	-1	($854,930)	84.62	-2	($1,652,930)	10,103.1	
	-2	($1,709,860)	84.11	-3	($2,479,395)	10,148.6	
	-3	($2,564,790)	83.60	-4	($3,305,860)	10,194.1	
	-4	($3,419,720)	83.10	-4.257	($3,518,261)	10,205.8	****
	-5	($4,274,650)	82.59	-5	($4,132,325)	10,239.7	
	-6	($5,129,580)	82.09	-6	($4,958,790)	10,285.2	
	-7	($5,984,510)	81.58	-7	($5,785,255)	10,330.7	
	-8	($6,839,440)	81.07	-8	($6,611,720)	10,376.3	
	-9	($7,694,370)	80.57	-9	($7,438,185)	10,421.8	
	-10	($8,549,300)	80.06	-10	($8,264,649)	10,467.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.54%	10.36%

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,488,200	87.29	10	$3,565,143	7,053.9	
	9	$2,239,380	87.00	9	$3,208,629	7,070.1	
	8	$1,990,560	86.70	8	$2,852,115	7,086.3	
	7	$1,741,740	86.40	7	$2,495,600	7,102.5	
****	6.89	$1,714,370	86.37	6	$2,139,086	7,118.7	
	6	$1,492,920	86.10	5	$1,782,572	7,134.8	
	5	$1,244,100	85.80	4	$1,426,057	7,151.0	
	4	$995,280	85.51	3	$1,069,543	7,167.2	
	3	$746,460	85.21	2	$713,029	7,183.4	
	2	$497,640	84.91	1	$356,514	7,199.6	
	1	$248,820	84.61	0	$0	7,215.8	
		$0	84.31	0	$0	7,290.8	
	0	$0	84.31	0	$0	7,365.8	
		$0	84.31	-1	($356,514)	7,381.9	
	-1	($513,150)	83.72	-2	($713,029)	7,398.1	
	-2	($1,026,300)	83.12	-2.324	($828,539)	7,403.4	****
	-3	($1,539,450)	82.53	-3	($1,069,543)	7,414.3	
	-4	($2,052,600)	81.94	-4	($1,426,057)	7,430.5	
	-5	($2,565,750)	81.34	-5	($1,782,572)	7,446.7	
	-6	($3,078,900)	80.75	-6	($2,139,086)	7,462.9	
	-7	($3,592,050)	80.15	-7	($2,495,600)	7,479.0	
	-8	($4,105,200)	79.56	-8	($2,852,115)	7,495.2	
	-9	($4,618,350)	78.96	-9	($3,208,629)	7,511.4	
	-10	($5,131,500)	78.37	-10	($3,565,143)	7,527.6	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.12%	4.47%

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Hines 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$2,334,600	88.74	10	$4,467,129	6,885.5	
	10	$2,334,600	88.74	9	$4,020,416	6,905.3	
	9	$2,101,140	88.49	8	$3,573,704	6,925.1	
	8	$1,867,680	88.25	7	$3,126,991	6,944.8	
	7	$1,634,220	88.00	6	$2,680,278	6,964.6	
	6	$1,400,760	87.75	5	$2,233,565	6,984.4	
	5	$1,167,300	87.50	4	$1,786,852	7,004.2	
	4	$933,840	87.26	3	$1,340,139	7,024.0	
	3	$700,380	87.01	2	$893,426	7,043.8	
	2	$466,920	86.76	1	$446,713	7,063.6	
	1	$233,460	86.51	0	$0	7,083.4	
		$0	86.26	0.000	$0	7,135.5	****
	0	$0	86.26	0	$0	7,158.4	
		$0	86.26	0	$0	7,233.4	
	-1	($437,090)	85.75	-1	($446,713)	7,253.1	
	-2	($874,180)	85.25	-2	($893,426)	7,272.9	
	-3	($1,311,270)	84.74	-3	($1,340,139)	7,292.7	
	-4	($1,748,360)	84.23	-4	($1,786,852)	7,312.5	
	-5	($2,185,450)	83.72	-5	($2,233,565)	7,332.3	
	-6	($2,622,540)	83.21	-6	($2,680,278)	7,352.1	
	-7	($3,059,630)	82.70	-7	($3,126,991)	7,371.9	
	-8	($3,496,720)	82.19	-8	($3,573,704)	7,391.6	
	-9	($3,933,810)	81.68	-9	($4,020,416)	7,411.4	
	-10	($4,370,900)	81.17	-10	($4,467,129)	7,431.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.93%	5.60%

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Hines 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$1,574,900	80.98	10	$5,171,057	6,855.9	
	10	$1,574,900	80.98	9	$4,653,951	6,879.5	
	9	$1,417,410	80.85	8	$4,136,845	6,903.0	
	8	$1,259,920	80.71	7	$3,619,740	6,926.6	
	7	$1,102,430	80.57	6	$3,102,634	6,950.2	
	6	$944,940	80.44	5	$2,585,528	6,973.7	
	5	$787,450	80.30	4	$2,068,423	6,997.3	
	4	$629,960	80.16	3	$1,551,317	7,020.8	
	3	$472,470	80.03	2	$1,034,211	7,044.4	
	2	$314,980	79.89	1	$517,106	7,068.0	
	1	$157,490	79.75	0	$0	7,091.5	
		$0	79.62	0	$0	7,166.5	
	0	$0	79.62	0	$0	7,241.5	
		$0	79.62	-1	($361,974)	7,265.1	
	-1	($274,840)	79.33	-1.189	($614,839)	7,269.5	****
	-2	($549,680)	79.05	-2	($1,034,211)	7,288.6	
	-3	($824,520)	78.77	-3	($1,551,317)	7,312.2	
	-4	($1,099,360)	78.48	-4	($2,068,423)	7,335.8	
	-5	($1,374,200)	78.20	-5	($2,585,528)	7,359.3	
	-6	($1,649,040)	77.92	-6	($3,102,634)	7,382.9	
	-7	($1,923,880)	77.64	-7	($3,619,740)	7,406.4	
	-8	($2,198,720)	77.35	-8	($4,136,845)	7,430.0	
	-9	($2,473,560)	77.07	-9	($4,653,951)	7,453.6	
	-10	($2,748,400)	76.79	-10	($5,171,057)	7,477.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.97%	6.48%

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Janauary 2012 - December 2012

Unit: Hines 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$2,076,300	84.69	10	$5,325,220	6,658.4	
	10	$2,076,300	84.69	9	$4,792,698	6,681.1	
	9	$1,868,670	84.48	8	$4,260,176	6,703.9	
	8	$1,661,040	84.27	7	$3,727,654	6,726.6	
	7	$1,453,410	84.07	6	$3,195,132	6,749.3	
	6	$1,245,780	83.86	5	$2,662,610	6,772.1	
	5	$1,038,150	83.65	4	$2,130,088	6,794.8	
	4	$830,520	83.44	3	$1,597,566	6,817.6	
	3	$622,890	83.24	2	$1,065,044	6,840.3	
	2	$415,260	83.03	1.561	$831,267	6,850.3	****
	1	$207,630	82.82	1	$532,522	6,863.0	
		$0	82.61	0	$0	6,885.8	
	0	$0	82.61	0	$0	6,960.8	
		$0	82.61	0	$0	7,035.8	
	-1	($338,700)	82.18	-1	($532,522)	7,058.5	
	-2	($677,400)	81.75	-2	($1,065,044)	7,081.3	
	-3	($1,016,100)	81.33	-3	($1,597,566)	7,104.0	
	-4	($1,354,800)	80.90	-4	($2,130,088)	7,126.7	
	-5	($1,693,500)	80.47	-5	($2,662,610)	7,149.5	
	-6	($2,032,200)	80.04	-6	($3,195,132)	7,172.2	
	-7	($2,370,900)	79.61	-7	($3,727,654)	7,195.0	
	-8	($2,709,600)	79.18	-8	($4,260,176)	7,217.7	
	-9	($3,048,300)	78.75	-9	($4,792,698)	7,240.4	
	-10	($3,387,000)	78.32	-10	($5,325,220)	7,263.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.60%	6.67%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Bartow CC	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	99.97	80.93	39.96	58.87	92.90	96.63	97.91	98.37	95.53	94.99	83.16	99.48	86.37
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	667.1	491.9	296.2	366.0	686.0	607.2	734.0	736.7	679.5	710.5	596.9	634.1	7,205.9
4. RSH	76.9	71.4	0.7	60.2	8.2	92.6	0.0	0.0	14.5	6.7	5.5	110.0	446.9
5. UH	0.0	132.7	446.1	293.8	49.8	20.2	10.1	7.3	26.0	26.8	118.6	0.0	1,131.2
6. POH	0.0	132.7	433.2	232.9	49.8	0.0	0.0	0.0	0.0	0.0	101.6	0.0	950.2
7. FOH	0.0	0.0	0.0	28.7	0.0	4.0	10.1	7.3	0.0	18.3	16.9	0.0	85.4
8. MOH	0.0	0.0	12.9	32.2	0.0	16.2	0.0	0.0	26.0	8.5	0.0	0.0	95.7
9. PPOH	0.0	0.0	0.0	13.6	121.3	0.0	0.0	0.0	0.0	0.0	252.0	149.3	536.2
10. LR PP (MW)	0.0	0.0	0.0	9.7	9.7	0.0	0.0	0.0	0.0	0.0	62.7	57.2	47.8
11. PFOH	0.0	0.0	0.0	50.7	281.7	282.3	314.6	302.4	273.3	413.2	273.0	281.7	2,472.9
12. LR PF (MW)	0.0	0.0	0.0	3.3	12.3	15.4	16.5	15.8	12.4	27.7	11.8	12.2	15.9
13. PMOH	5.2	0.0	0.0	37.0	0.0	4.9	21.2	17.1	63.4	9.8	0.0	13.3	171.9
14. LR PM (MW)	55.3	0.0	0.0	69.5	0.0	50.6	50.2	39.5	57.2	43.3	0.0	72.9	57.4
15. NSC (MW)	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133
16. OPER MBTU	4,793,071	3,431,342	3,384,281	3,600,292	4,869,374	3,987,450	5,050,598	5,105,931	4,680,190	4,738,166	3,916,257	4,237,993	51,794,944
17. NET GEN (MWH)	666,430	477,372	311,586	361,443	671,701	543,787	687,498	712,457	636,769	660,658	539,400	588,952	6,858,053
18. ANOHR (BTU/KWH)	7,192.2	7,188.0	10,861.5	9,960.9	7,249.3	7,332.7	7,346.3	7,166.7	7,349.9	7,171.9	7,260.4	7,195.8	7,552.4
19. NOF (%)	88.18	85.66	92.86	87.16	86.42	79.04	82.68	85.36	82.71	82.08	79.75	81.98	84.00
20. NPC (MW)	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133
ANOHR EQUATION:	ANOHR=	-5.456	x NOF +	7,799.13									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 4	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	98.53	93.18	99.02	87.20	98.46	97.78	92.41	84.71	96.29	96.54	98.23	86.32	94.05
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	735.0	690.8	743.0	633.7	742.6	720.0	737.9	696.4	720.0	735.2	719.5	642.7	8,516.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	9.0	5.2	0.0	86.3	1.4	0.0	6.1	47.6	0.0	8.8	1.5	101.3	267.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	5.2	0.0	0.0	1.4	0.0	6.1	0.0	0.0	8.8	0.0	0.0	21.5
8. MOH	9.0	0.0	0.0	86.3	0.0	0.0	0.0	47.6	0.0	0.0	1.5	101.3	245.7
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	12.0	17.5	0.0	0.0	3.7	10.5	425.0	640.2	118.7	35.7	0.0	0.0	1,263.2
12. LR PF (MW)	74.0	236.0	0.0	0.0	212.9	48.5	65.0	63.1	40.2	29.6	0.0	0.0	63.5
13. PMOH	9.0	279.5	23.0	13.8	30.1	27.0	30.8	56.2	46.8	111.5	17.0	4.0	648.5
14. LR PM (MW)	52.1	93.0	225.9	303.1	212.3	402.5	267.0	118.8	303.7	99.1	474.0	84.0	156.7
15. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
16. OPER MBTU	3,026,828	3,092,048	4,208,785	3,669,134	4,065,290	3,919,167	4,286,094	3,968,961	3,747,280	4,335,091	4,250,231	3,354,010	45,922,919
17. NET GEN (MWH)	287,051	287,338	401,376	351,927	394,088	360,276	412,381	371,701	351,688	416,683	420,720	317,291	4,372,520
18. ANOHR (BTU/KWH)	10,544.6	10,761.0	10,485.9	10,425.8	10,315.7	10,878.2	10,393.5	10,677.8	10,655.1	10,403.8	10,102.3	10,570.8	10,502.6
19. NOF (%)	54.85	58.42	75.87	78.00	74.53	70.28	78.49	74.97	68.60	79.60	82.12	69.34	72.11
20. NPC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
ANOHR EQUATION:	ANOHR=	-44.533	x NOF +	13,667.13									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 5	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	95.91	98.90	98.06	82.36	97.23	97.94	99.15	98.72	99.15	71.48	0.00	2.19	78.40
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	542.5	693.0	735.4	632.2	735.6	720.0	744.0	744.0	720.0	533.1	0.0	16.3	6,816.1
4. RSH	186.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	186.9
5. UH	14.7	3.0	7.6	87.8	8.4	0.0	0.0	0.0	0.0	210.9	721.0	727.7	1,781.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	118.9	721.0	727.7	1,567.6
7. FOH	14.7	3.0	7.6	7.7	8.4	0.0	0.0	0.0	0.0	92.0	0.0	0.0	133.3
8. MOH	0.0	0.0	0.0	80.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.2
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	1.3	1.6	0.0	12.8	9.5	45.6	30.5	2.1	6.6	4.0	0.0	0.0	113.9
12. LR PF (MW)	329.0	706.5	0.0	329.0	567.0	97.4	98.7	171.5	72.0	91.0	0.0	0.0	173.5
13. PMOH	76.8	17.3	43.3	154.7	35.1	19.6	16.0	70.4	18.6	10.0	0.0	0.0	461.6
14. LR PM (MW)	140.6	125.8	112.1	152.6	93.0	312.1	91.0	91.0	209.4	58.0	0.0	0.0	136.8
15. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
16. OPER MBTU	1,316,069	3,150,246	3,915,899	3,323,270	3,608,949	3,621,483	4,283,712	4,217,622	3,743,883	2,776,045	0	67,210	34,024,388
17. NET GEN (MWH)	119,879	288,878	372,595	316,985	347,097	330,791	405,529	390,603	349,109	266,316	0	1,181	3,188,963
18. ANOHR (BTU/KWH)	10,978.3	10,905.1	10,509.8	10,484.0	10,397.5	10,947.9	10,563.3	10,797.7	10,724.1	10,423.9	0.0	56,909.4	10,669.4
19. NOF (%)	31.13	58.71	71.36	70.62	66.46	64.71	76.77	73.94	68.29	70.36	0.00	10.19	65.90
20. NPC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710

ANOHR EQUATION: ANOHR= -20.469 x NOF + 11,749.39

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Hines 1	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	97.27	100.00	99.92	43.37	39.25	99.86	100.00	94.70	97.29	100.00	97.25	96.58	88.50
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	744.0	696.0	743.0	312.8	321.1	720.0	744.0	719.0	701.0	744.0	721.0	718.6	7,884.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	407.2	422.9	0.0	0.0	25.0	19.0	0.0	0.0	25.4	899.5
6. POH	0.0	0.0	0.0	407.2	187.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	594.9
7. FOH	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0	19.0	0.0	0.0	25.4	56.0
8. MOH	0.0	0.0	0.0	0.0	223.6	0.0	0.0	25.0	0.0	0.0	0.0	0.0	248.6
9. PPOH	0.0	0.0	0.0	0.0	103.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.6
10. LR PP (MW)	0.0	0.0	0.0	0.0	109.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	109.2
11. PFOH	41.2	0.0	0.0	1.5	0.0	1.9	0.0	22.0	0.0	0.0	0.0	0.0	66.5
12. LR PF (MW)	228.0	0.0	0.0	174.0	0.0	241.6	0.0	292.0	0.0	0.0	0.0	0.0	248.3
13. PMOH	0.0	0.0	1.4	0.0	45.3	0.0	0.0	1.3	2.0	0.0	42.7	0.0	92.7
14. LR PM (MW)	0.0	0.0	199.0	0.0	297.0	0.0	0.0	198.5	130.2	0.0	214.6	0.0	252.6
15. NSC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
16. OPER MBTU	2,134,690	2,344,268	2,455,892	1,003,072	853,501	2,232,087	2,238,188	2,385,286	2,276,167	2,390,069	2,067,432	2,161,314	24,541,965
17. NET GEN (MWH)	308,766	328,197	345,245	139,344	113,005	300,630	308,140	307,458	313,626	314,496	259,894	298,861	3,337,662
18. ANOHR (BTU/KWH)	6,913.6	7,142.9	7,113.5	7,198.5	7,552.8	7,424.7	7,263.5	7,758.1	7,257.6	7,599.7	7,954.9	7,231.8	7,353.0
19. NOF (%)	89.83	102.07	100.58	96.43	76.17	90.38	89.65	92.56	96.84	91.50	78.02	90.02	91.63
20. NPC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
ANOHR EQUATION:	ANOHR=	-6.262	x NOF +	7,814.20									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Hines 2	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	99.77	100.00	29.31	93.48	99.91	99.91	100.00	99.92	99.91	100.00	99.90	100.00	93.43
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	744.0	403.2	217.8	680.7	744.0	720.0	744.0	744.0	720.0	744.0	721.0	744.0	7,926.6
4. RSH	0.0	292.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	292.8
5. UH	0.0	0.0	525.2	39.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	564.6
6. POH	0.0	0.0	525.2	39.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	564.6
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
12. LR PF (MW)	265.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	265.3
13. PMOH	3.3	0.0	0.0	12.1	2.6	2.4	0.0	2.0	2.0	0.0	2.0	0.0	26.2
14. LR PM (MW)	149.0	0.0	0.0	309.7	127.0	127.0	0.0	147.0	158.3	0.0	170.3	0.0	221.0
15. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
16. OPER MBTU	2,122,509	1,059,539	749,387	2,283,528	2,523,317	2,253,577	2,269,292	2,306,351	2,334,727	2,236,740	2,311,705	1,563,852	24,014,523
17. NET GEN (MWH)	301,209	142,685	105,293	321,551	356,644	317,186	317,412	326,640	329,289	321,027	318,299	217,070	3,374,305
18. ANOHR (BTU/KWH)	7,046.6	7,425.7	7,117.2	7,101.6	7,075.2	7,104.9	7,149.4	7,060.8	7,090.2	6,967.5	7,262.7	7,204.4	7,116.9
19. NOF (%)	82.62	72.22	98.67	96.41	97.83	89.91	87.07	89.60	93.34	88.06	90.10	59.54	86.88
20. NPC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
ANOHR EQUATION:	ANOHR=	-2.362	x NOF +	7,344.88									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Hines 3	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	99.93	100.00	6.74	26.54	99.96	99.96	99.66	97.47	100.00	38.28	95.52	100.00	79.56
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	744.0	696.0	50.1	191.1	744.0	720.0	744.0	744.0	720.0	287.8	688.7	744.0	7,073.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	692.9	528.9	0.0	0.0	0.0	0.0	0.0	456.2	32.3	0.0	1,710.3
6. POH	0.0	0.0	692.9	528.9	0.0	0.0	0.0	0.0	0.0	456.2	32.3	0.0	1,710.3
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	0.0	90.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.1
10. LR PP (MW)	0.0	0.0	0.0	323.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	323.0
11. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	3.8	28.9	0.0	0.0	0.0	0.0	32.7
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	328.3	318.0	0.0	0.0	0.0	0.0	319.2
13. PMOH	2.1	0.0	0.0	0.0	1.2	1.3	0.0	0.0	0.0	4.7	0.0	0.0	9.2
14. LR PM (MW)	125.0	0.0	0.0	0.0	125.4	125.0	0.0	0.0	0.0	318.2	0.0	0.0	223.8
15. NSC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
16. OPER MBTU	1,937,960	2,154,195	111,473	491,778	2,421,782	2,388,758	2,406,557	2,281,177	2,418,523	890,209	2,169,758	2,171,320	21,843,488
17. NET GEN (MWH)	262,873	301,502	23,070	67,463	332,901	329,300	320,609	322,712	328,691	116,107	292,137	296,089	2,993,454
18. ANOHR (BTU/KWH)	7,372.2	7,144.9	4,831.9	7,289.6	7,274.8	7,254.0	7,506.2	7,068.8	7,358.0	7,667.1	7,427.2	7,333.3	7,297.1
19. NOF (%)	72.40	88.77	94.42	72.33	91.69	93.72	88.30	88.88	93.55	82.66	86.93	81.55	86.72
20. NPC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
ANOHR EQUATION:	ANOHR=	-16.737	x NOF +	8,645.48									

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Hines 4	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-Dec Period
1. EAF	99.90	99.68	99.31	81.77	57.72	97.31	99.64	100.00	99.95	99.85	36.33	99.79	86.60
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	712.6	689.4	743.0	625.5	429.4	687.6	744.0	744.0	720.0	744.0	261.9	742.5	7,843.9
4. RSH	31.5	4.4	0.0	0.0	0.0	20.1	0.0	0.0	0.0	0.0	0.0	0.0	55.9
5. UH	0.0	2.3	0.0	94.5	314.6	12.3	0.0	0.0	0.0	0.0	459.1	1.5	884.2
6. POH	0.0	0.0	0.0	94.5	314.6	0.0	0.0	0.0	0.0	0.0	459.1	0.0	868.2
7. FOH	0.0	2.3	0.0	0.0	0.0	12.3	0.0	0.0	0.0	0.0	0.0	1.5	16.1
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	0.0	0.0	367.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	367.9
10. LR PP (MW)	0.0	0.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	307.0
11. PFOH	0.0	0.0	0.6	51.9	0.0	6.1	2.7	0.0	0.0	0.0	0.0	0.0	61.3
12. LR PF (MW)	0.0	0.0	226.8	307.0	0.0	318.2	362.0	0.0	0.0	0.0	0.0	0.0	309.7
13. PMOH	2.5	0.0	11.6	6.7	0.0	7.3	2.2	0.0	1.3	3.8	0.0	0.0	35.4
14. LR PM (MW)	145.0	0.0	196.8	208.0	0.0	193.6	140.4	0.0	139.6	140.1	0.0	0.0	182.9
15. NSC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
16. OPER MBTU	1,769,495	1,478,102	2,486,690	1,983,183	770,331	2,215,916	2,248,479	2,413,181	2,334,287	2,324,637	632,429	1,895,544	22,552,274
17. NET GEN (MWH)	254,994	209,174	361,943	285,723	109,244	321,128	330,682	346,876	339,573	346,700	115,579	271,475	3,293,091
18. ANOHR (BTU/KWH)	6,939.4	7,066.4	6,870.4	6,940.9	7,051.5	6,900.4	6,799.5	6,956.9	6,874.2	6,705.0	5,471.8	6,982.4	6,848.4
19. NOF (%)	75.82	64.28	103.21	96.78	53.90	98.95	94.17	98.78	99.92	98.73	93.49	77.47	88.95
20. NPC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
ANOHR EQUATION:	ANOHR=	-7.104	x NOF +	7,590.72									

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PLANNED OUTAGE SCHEDULES
ACTUAL

Progress Energy Florida
Janauary 2012 - December 2012

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow Unit 4	02/23 (2300) - 05/14 (0900)	Turbine Valves
Bartow Unit 4	11/02 (0200) - 12/17 (0400)	Hot Gas Path Inspection
Crystal River 5	10/27 (0100) - 12/31 (1700)	Major Outage
Hines 1	04/14 (0000) - 05/13 (0400)	Major Outage
Hines 2	03/10 (0146) - 04/02 (1521)	Major Unit Inspection
Hines 3	03/03 (0200) - 04/27 (0300)	Major Outage
Hines 3	10/12 (2349) - 11/02 (0819)	Boroscope Inspection
Hines 4	04/27 (0100) - 05/29 (1100)	Hot Gas Path Inspection
Hines 4	11/02 (2326) - 11/22 (0130)	Boroscope Inspection

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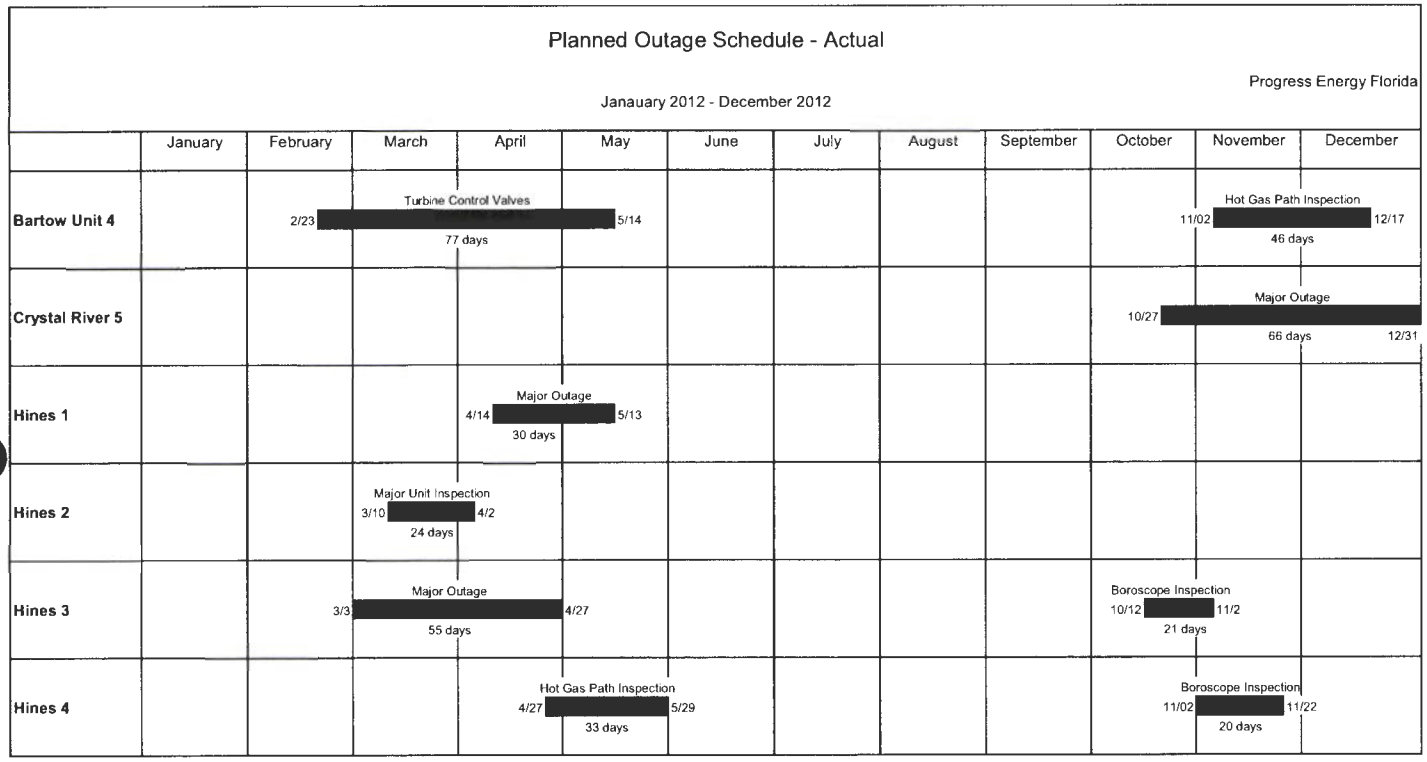
Effective:
Docket No.:
Order No.:

Planned Outage Schedule - Actual

Progress Energy Florida

Janauary 2012 - December 2012



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Effective:
Docket No.:
Order No.:

GPIF Targets and Ranges for January through December 2014

STANDARD FORM GPIF SCHEDULES

Description	Page
Index	1
Reward/Penalty Table (Estimated)	2
Maximum Incentive Dollars (Estimated)	3
Target and Range Summary	4
Comparison of Targets with Prior Period Performance	5-6
Derivation of Weighting Factors	7
Incentive Points Tables	8-15
Unit Performance Data (Estimated)	16-23
Planned Outage Schedule (Estimated)	24-25
Average Net Operating Heat Rate Curves	26-40
Unplanned Outage Rate Tables and Graphs	41-77

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 30
PARTY Duke Energy Florida, Inc. (DEF) (Direct)
DESCRIPTION Matthew Jones - MJJ-1P

Original Sheet No. 7.101.1

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Duke Energy Florida
Period of: January 2014 - December 2014

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$62,118,265	$20,529,186
9	$55,906,438	$18,476,267
8	$49,694,612	$16,423,348
7	$43,482,785	$14,370,430
6	$37,270,959	$12,317,511
5	$31,059,132	$10,264,593
4	$24,847,306	$8,211,674
3	$18,635,479	$6,158,756
2	$12,423,653	$4,105,837
1	$6,211,826	$2,052,919
0	$0	$0
-1	($7,226,206)	($2,052,919)
-2	($14,452,413)	($4,105,837)
-3	($21,678,619)	($6,158,756)
-4	($28,904,826)	($8,211,674)
-5	($36,131,032)	($10,264,593)
-6	($43,357,239)	($12,317,511)
-7	($50,583,445)	($14,370,430)
-8	($57,809,652)	($16,423,348)
-9	($65,035,858)	($18,476,267)
-10	($72,262,065)	($20,529,186)

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.102.1

GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Duke Energy Florida
Period of: January 2014 - December 2014

1	Beginning of period balance of common equity	$5,176,743,074
	END OF MONTH BALANCE OF COMMON EQUITY:	
2	Month of JANUARY 2014	$5,071,865,625
3	Month of FEBRUARY 2014	$5,113,928,665
4	Month of MARCH 2014	$5,149,121,051
5	Month of APRIL 2014	$5,008,325,383
6	Month of MAY 2014	$5,069,502,984
7	Month of JUNE 2014	$5,145,016,149
8	Month of JULY 2014	$5,223,808,969
9	Month of AUGUST 2014	$5,298,546,257
10	Month of SEPTEMBER 2014	$5,193,326,658
11	Month of OCTOBER 2014	$5,235,656,242
12	Month of NOVEMBER 2014	$5,277,135,281
13	Month of DECEMBER 2014	$5,345,793,409
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$5,177,597,673
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	61.3808%
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$21,088,018
18	Jurisdictional Sales	37,863,418 MWH
19	Total Sales	38,895,701 MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	97.35%
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$20,529,186

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Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.103.1

GPIF TARGET AND RANGE SUMMARY

Duke Energy Florida
Period of: January 2014 - December 2014

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	5.09	92.11	93.76	88.70	3,164	(4,640)
Crystal River 4	6.67	87.77	90.92	81.46	4,141	(7,677)
Crystal River 5	5.32	89.40	91.68	84.76	3,302	(5,682)
Hines 1	1.53	82.65	84.43	79.03	948	(2,061)
Hines 2	0.99	87.29	88.70	84.38	612	(1,034)
Hines 3	0.19	90.91	91.13	90.46	117	(1,377)
Hines 4	1.68	90.39	91.18	88.74	1,043	(998)
GPIF System	21.45				13,326	(23,469)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	26.04	7,317	87.8	6,872	7,762	16,174	(16,174)
Crystal River 4	13.00	10,267	78.1	9,750	10,783	8,073	(8,073)
Crystal River 5	12.72	10,279	76.8	9,754	10,804	7,899	(7,899)
Hines 1	6.91	7,387	84.7	7,028	7,747	4,293	(4,293)
Hines 2	6.13	7,212	77.1	6,919	7,504	3,805	(3,805)
Hines 3	6.80	7,315	83.4	7,019	7,610	4,224	(4,224)
Hines 4	6.96	6,921	89.9	6,646	7,196	4,325	(4,325)
GPIF System	78.55					48,793	(48,793)

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.104.1

COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Duke Energy Florida
Period of: January 2014 - December 2014

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2013 POF	Actual Performance 1st Prior Period Jan-Jun 2013 EUOF	Actual Performance 1st Prior Period Jan-Jun 2013 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2012 POF	Actual Performance 2nd Prior Period Jan-Dec 2012 EUOF	Actual Performance 2nd Prior Period Jan-Dec 2012 EUOR
Bartow 4	4.98	21.47	4.38	3.51	3.52	9.31	3.01	3.61	10.82	2.56	3.04
Crystal River 4	6.52	28.09	5.48	6.75	7.18	11.90	9.83	11.16	0.00	5.95	5.95
Crystal River 5	5.20	22.40	5.75	4.84	5.15	0.00	9.48	9.48	17.85	3.76	4.70
Hines 1	1.49	6.43	13.56	3.78	4.74	13.79	0.97	1.12	6.77	4.45	4.77
Hines 2	0.96	4.15	9.73	2.98	3.56	11.41	4.08	5.19	6.43	0.14	0.16
Hines 3	0.18	0.79	8.63	0.46	0.52	3.95	0.00	0.00	19.47	0.29	0.36
Hines 4	3.86	16.66	7.95	1.67	1.78	0.00	0.52	0.52	9.88	0.80	0.89
GPIF System Wghtd. Avg.	23.20	100.00	6.44	4.38	4.68	6.73	5.85	6.41	8.82	3.49	3.84

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2011 POF	Actual Performance 3rd Prior Period Jan-Dec 2011 EUOF	Actual Performance 3rd Prior Period Jan-Dec 2011 EUOR	Actual Performance 4th Prior Period Jan-Dec 2010 POF	Actual Performance 4th Prior Period Jan-Dec 2010 EUOF	Actual Performance 4th Prior Period Jan-Dec 2010 EUOR	Actual Performance 5th Prior Period Jan-Dec 2009 POF	Actual Performance 5th Prior Period Jan-Dec 2009 EUOF	Actual Performance 5th Prior Period Jan-Dec 2009 EUOR
Bartow 4	4.98	3.65	4.03	0.00	8.63	8.63	N/A	N/A	N/A
Crystal River 4	16.53	2.94	3.53	22.53	9.18	11.85	0.00	9.49	9.86
Crystal River 5	7.84	4.09	4.44	2.16	6.77	6.91	36.23	3.68	5.76
Hines 1	21.17	3.65	4.66	11.14	9.61	10.82	6.75	3.70	3.99
Hines 2	16.09	2.92	3.55	6.84	4.79	5.15	8.99	4.40	5.07
Hines 3	10.39	0.86	0.96	9.03	3.46	3.79	8.00	5.75	6.53
Hines 4	13.27	1.81	2.14	9.18	3.18	3.50	18.66	7.88	10.31
GPIF System Wghtd. Avg.	11.79	3.19	3.66	9.42	7.32	8.26	12.10	5.27	6.30

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.104.2

COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Duke Energy Florida
Period of: January 2014 - December 2014

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2012 - Dec 2012	2nd Prior HR Jan 2011 - Dec 2011	3rd Prior HR Jan 2010 - Dec 2010
Bartow 4	26.04	33.15	7,317	7,223	7,313	7,312
Crystal River 4	13.00	16.55	10,267	10,421	10,001	10,132
Crystal River 5	12.72	16.19	10,279	10,412	10,145	10,127
Hines 1	6.91	8.80	7,387	7,456	7,277	7,356
Hines 2	6.13	7.80	7,212	7,184	7,161	7,255
Hines 3	6.80	8.66	7,315	7,360	7,303	7,296
Hines 4	6.96	8.86	6,921	6,907	6,933	6,958
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
GPIF System Weighted Avg.	78.55	100.00	8,247	8,270	8,167	8,642

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Suspended:
Effective:
Docket No:

Original Sheet No. 7.105.1

DERIVATION OF WEIGHTING FACTORS

Duke Energy Florida
Period of: January 2014 - December 2014

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Bartow 4 EA	2,200,652	2,197,488	3,164	5.09
Bartow 4 HR	2,200,652	2,184,478	16,174	26.04
Crystal River 4 EA	2,200,652	2,196,512	4,141	6.67
Crystal River 4 HR	2,200,652	2,192,579	8,073	13.00
Crystal River 5 EA	2,200,652	2,197,350	3,302	5.32
Crystal River 5 HR	2,200,652	2,192,753	7,899	12.72
Hines 1 EA	2,200,652	2,199,704	948	1.53
Hines 1 HR	2,200,652	2,196,359	4,293	6.91
Hines 2 EA	2,200,652	2,200,040	612	0.99
Hines 2 HR	2,200,652	2,196,847	3,805	6.13
Hines 3 EA	2,200,652	2,200,536	117	0.19
Hines 3 HR	2,200,652	2,196,429	4,224	6.80
Hines 4 EA	2,200,652	2,199,610	1,043	1.68
Hines 4 HR	2,200,652	2,196,328	4,325	6.96

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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INCENTIVE POINTS TABLES

Original Sheet No. 7.106.1

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Bartow 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$3,163,900	93.76	10	$16,173,774	6,871.5
9	$2,847,510	93.60	9	$14,556,396	6,908.5
8	$2,531,120	93.43	8	$12,939,019	6,945.6
7	$2,214,730	93.27	7	$11,321,642	6,982.6
6	$1,898,340	93.10	6	$9,704,264	7,019.6
5	$1,581,950	92.93	5	$8,086,887	7,056.7
4	$1,265,560	92.77	4	$6,469,509	7,093.7
3	$949,170	92.60	3	$4,852,132	7,130.7
2	$632,780	92.44	2	$3,234,755	7,167.8
1	$316,390	92.27	1	$1,617,377	7,204.8
					7,241.8
0	$0	92.11	0	$0	7,316.8
					7,391.8
-1	($463,990)	91.77	-1	($1,617,377)	7,428.8
-2	($927,980)	91.43	-2	($3,234,755)	7,465.9
-3	($1,391,970)	91.09	-3	($4,852,132)	7,502.9
-4	($1,855,960)	90.75	-4	($6,469,509)	7,539.9
-5	($2,319,950)	90.41	-5	($8,086,887)	7,577.0
-6	($2,783,940)	90.06	-6	($9,704,264)	7,614.0
-7	($3,247,930)	89.72	-7	($11,321,642)	7,651.0
-8	($3,711,920)	89.38	-8	($12,939,019)	7,688.1
-9	($4,175,910)	89.04	-9	($14,556,396)	7,725.1
-10	($4,639,900)	88.70	-10	($16,173,774)	7,762.1

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.09%	26.04%

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Docket No.:
Order No.:

Original Sheet No. 7.106.2

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$4,140,600	90.92	10	$8,072,985	9,749.8
9	$3,726,540	90.60	9	$7,265,687	9,794.0
8	$3,312,480	90.29	8	$6,458,388	9,838.2
7	$2,898,420	89.97	7	$5,651,090	9,882.3
6	$2,484,360	89.66	6	$4,843,791	9,926.5
5	$2,070,300	89.34	5	$4,036,493	9,970.7
4	$1,656,240	89.03	4	$3,229,194	10,014.8
3	$1,242,180	88.72	3	$2,421,896	10,059.0
2	$828,120	88.40	2	$1,614,597	10,103.2
1	$414,060	88.09	1	$807,299	10,147.3
					10,191.5
0	$0	87.77	0	$0	10,266.5
					10,341.5
-1	($767,700)	87.14	-1	($807,299)	10,385.7
-2	($1,535,400)	86.51	-2	($1,614,597)	10,429.8
-3	($2,303,100)	85.88	-3	($2,421,896)	10,474.0
-4	($3,070,800)	85.25	-4	($3,229,194)	10,518.2
-5	($3,838,500)	84.62	-5	($4,036,493)	10,562.3
-6	($4,606,200)	83.98	-6	($4,843,791)	10,606.5
-7	($5,373,900)	83.35	-7	($5,651,090)	10,650.7
-8	($6,141,600)	82.72	-8	($6,458,388)	10,694.8
-9	($6,909,300)	82.09	-9	($7,265,687)	10,739.0
-10	($7,677,000)	81.46	-10	($8,072,985)	10,783.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.67%	13.00%

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.106.3

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$3,301,900	91.68	10	$7,899,450	9,753.7
9	$2,971,710	91.45	9	$7,109,505	9,798.7
8	$2,641,520	91.22	8	$6,319,560	9,843.8
7	$2,311,330	91.00	7	$5,529,615	9,888.8
6	$1,981,140	90.77	6	$4,739,670	9,933.8
5	$1,650,950	90.54	5	$3,949,725	9,978.8
4	$1,320,760	90.31	4	$3,159,780	10,023.9
3	$990,570	90.09	3	$2,369,835	10,068.9
2	$660,380	89.86	2	$1,579,890	10,113.9
1	$330,190	89.63	1	$789,945	10,158.9
					10,203.9
0	$0	89.40	0	$0	10,278.9
					10,353.9
-1	($568,230)	88.94	-1	($789,945)	10,399.0
-2	($1,136,460)	88.48	-2	($1,579,890)	10,444.0
-3	($1,704,690)	88.01	-3	($2,369,835)	10,489.0
-4	($2,272,920)	87.55	-4	($3,159,780)	10,534.0
-5	($2,841,150)	87.08	-5	($3,949,725)	10,579.1
-6	($3,409,380)	86.62	-6	($4,739,670)	10,624.1
-7	($3,977,610)	86.16	-7	($5,529,615)	10,669.1
-8	($4,545,840)	85.69	-8	($6,319,560)	10,714.1
-9	($5,114,070)	85.23	-9	($7,109,505)	10,759.2
-10	($5,682,300)	84.76	-10	($7,899,450)	10,804.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.32%	12.72%

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.106.4

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$948,100	84.43	10	$4,292,766	7,028.0
9	$853,290	84.25	9	$3,863,490	7,056.4
8	$758,480	84.08	8	$3,434,213	7,084.9
7	$663,670	83.90	7	$3,004,936	7,113.3
6	$568,860	83.72	6	$2,575,660	7,141.7
5	$474,050	83.54	5	$2,146,383	7,170.2
4	$379,240	83.36	4	$1,717,106	7,198.6
3	$284,430	83.19	3	$1,287,830	7,227.0
2	$189,620	83.01	2	$858,553	7,255.5
1	$94,810	82.83	1	$429,277	7,283.9
					7,312.3
0	$0	82.65	0	$0	7,387.3
					7,462.3
-1	($206,130)	82.29	-1	($429,277)	7,490.8
-2	($412,260)	81.93	-2	($858,553)	7,519.2
-3	($618,390)	81.57	-3	($1,287,830)	7,547.6
-4	($824,520)	81.20	-4	($1,717,106)	7,576.1
-5	($1,030,650)	80.84	-5	($2,146,383)	7,604.5
-6	($1,236,780)	80.48	-6	($2,575,660)	7,632.9
-7	($1,442,910)	80.12	-7	($3,004,936)	7,661.4
-8	($1,649,040)	79.76	-8	($3,434,213)	7,689.8
-9	($1,855,170)	79.39	-9	($3,863,490)	7,718.2
-10	($2,061,300)	79.03	-10	($4,292,766)	7,746.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.53%	6.91%

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.106.5

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Hines 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$612,000	88.70	10	$3,805,478	6,919.5
9	$550,800	88.56	9	$3,424,930	6,941.2
8	$489,600	88.42	8	$3,044,382	6,963.0
7	$428,400	88.28	7	$2,663,835	6,984.7
6	$367,200	88.14	6	$2,283,287	7,006.5
5	$306,000	87.99	5	$1,902,739	7,028.2
4	$244,800	87.85	4	$1,522,191	7,050.0
3	$183,600	87.71	3	$1,141,643	7,071.7
2	$122,400	87.57	2	$761,096	7,093.4
1	$61,200	87.43	1	$380,548	7,115.2
					7,136.9
0	$0	87.29	0	$0	7,211.9
					7,286.9
-1	($103,380)	87.00	-1	($380,548)	7,308.7
-2	($206,760)	86.71	-2	($761,096)	7,330.4
-3	($310,140)	86.42	-3	($1,141,643)	7,352.2
-4	($413,520)	86.13	-4	($1,522,191)	7,373.9
-5	($516,900)	85.83	-5	($1,902,739)	7,395.7
-6	($620,280)	85.54	-6	($2,283,287)	7,417.4
-7	($723,660)	85.25	-7	($2,663,835)	7,439.2
-8	($827,040)	84.96	-8	($3,044,382)	7,460.9
-9	($930,420)	84.67	-9	($3,424,930)	7,482.7
-10	($1,033,800)	84.38	-10	($3,805,478)	7,504.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.99%	6.13%

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Hines 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$116,700	91.13	10	$4,223,534	7,019.0
9	$105,030	91.11	9	$3,801,181	7,041.1
8	$93,360	91.09	8	$3,378,828	7,063.1
7	$81,690	91.07	7	$2,956,474	7,085.2
6	$70,020	91.04	6	$2,534,121	7,107.2
5	$58,350	91.02	5	$2,111,767	7,129.3
4	$46,680	91.00	4	$1,689,414	7,151.4
3	$35,010	90.98	3	$1,267,060	7,173.4
2	$23,340	90.96	2	$844,707	7,195.5
1	$11,670	90.94	1	$422,353	7,217.5
					7,239.6
0	$0	90.91	0	$0	7,314.6
					7,389.6
-1	($137,680)	90.87	-1	($422,353)	7,411.7
-2	($275,360)	90.82	-2	($844,707)	7,433.7
-3	($413,040)	90.78	-3	($1,267,060)	7,455.8
-4	($550,720)	90.73	-4	($1,689,414)	7,477.8
-5	($688,400)	90.69	-5	($2,111,767)	7,499.9
-6	($826,080)	90.64	-6	($2,534,121)	7,522.0
-7	($963,760)	90.60	-7	($2,956,474)	7,544.0
-8	($1,101,440)	90.55	-8	($3,378,828)	7,566.1
-9	($1,239,120)	90.51	-9	($3,801,181)	7,588.1
-10	($1,376,800)	90.46	-10	($4,223,534)	7,610.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.19%	6.80%

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2014 - December 2014

Hines 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,042,500	91.18	10	$4,324,578	6,645.7
9	$938,250	91.10	9	$3,892,120	6,665.7
8	$834,000	91.02	8	$3,459,662	6,685.7
7	$729,750	90.94	7	$3,027,204	6,705.7
6	$625,500	90.86	6	$2,594,747	6,725.8
5	$521,250	90.78	5	$2,162,289	6,745.8
4	$417,000	90.70	4	$1,729,831	6,765.8
3	$312,750	90.63	3	$1,297,373	6,785.8
2	$208,500	90.55	2	$864,916	6,805.8
1	$104,250	90.47	1	$432,458	6,825.8
					6,845.8
0	$0	90.39	0	$0	6,920.8
					6,995.8
-1	($99,840)	90.22	-1	($432,458)	7,015.8
-2	($199,680)	90.06	-2	($864,916)	7,035.8
-3	($299,520)	89.89	-3	($1,297,373)	7,055.9
-4	($399,360)	89.73	-4	($1,729,831)	7,075.9
-5	($499,200)	89.56	-5	($2,162,289)	7,095.9
-6	($599,040)	89.40	-6	($2,594,747)	7,115.9
-7	($698,880)	89.23	-7	($3,027,204)	7,135.9
-8	($798,720)	89.07	-8	($3,459,662)	7,155.9
-9	($898,560)	88.91	-9	($3,892,120)	7,175.9
-10	($998,400)	88.74	-10	($4,324,578)	7,195.9

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.68%	6.96%

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

UNIT PERFORMANCE DATA

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Bartow 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.48	96.61	91.64	71.48	96.48	96.48	96.48	96.48	96.48	96.48	83.15	86.80	92.11
2. POF	0.00	0.00	4.84	25.00	0.00	0.00	0.00	0.00	0.00	0.00	13.33	9.68	4.38
3. EUOF	3.52	3.39	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.51
4. EUOR	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	726.1	632.4	726.1	702.7	726.1	702.7	726.1	726.1	702.7	726.1	702.7	726.1	8,525.8
7. RSH	0.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.0
8. UH	17.9	15.6	17.9	17.3	17.9	17.3	17.9	17.9	17.3	17.9	17.3	17.9	210.2
9. POH & PPOH	0.0	0.0	36.0	180.0	0.0	0.0	0.0	0.0	0.0	0.0	96.0	72.0	384.0
10. FOH & PFOH	19.0	16.6	19.0	18.4	19.0	18.4	19.0	19.0	18.4	19.0	18.4	19.0	223.2
11. MOH & PMOH	7.2	6.2	7.2	6.9	7.2	6.9	7.2	7.2	6.9	7.2	6.9	7.2	84.2
12. Oper. Btu(MBtu)	4,977,688	4,447,560	4,623,319	4,010,767	5,249,815	5,126,027	5,384,050	5,370,610	5,094,093	5,282,684	4,492,277	4,754,627	58,835,497
13. Net Gen. (MWH)	680,020.0	608,604.0	628,765.0	542,197.0	719,717.0	703,176.0	739,409.0	737,434.0	698,496.0	724,532.0	611,088.0	647,700.0	8,041,138.0
14. ANOHR (Btu/KWH)	7,320	7,308	7,353	7,397	7,294	7,290	7,282	7,283	7,293	7,291	7,351	7,341	7,317
15. NOF (%)	87.2	89.6	80.6	71.8	92.3	93.2	94.8	94.6	92.6	92.9	81.0	83.1	87.8
16. NSC (MW)	1074	1074	1074	1074	1074	1074	1074	1074	1074	1074	1074	1074	1074
17. ANOHR Equation	ANOHR=	-5.036 x NOF +		7,759.1									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	92.82	93.08	92.82	92.82	92.82	92.82	92.82	92.82	92.82	92.82	46.41	78.01	87.77
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00	16.13	5.48
3. EUOF	7.18	6.92	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	3.59	5.86	6.75
4. EUOR	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18	7.18
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	704.7	613.7	704.7	681.9	704.7	681.9	704.7	704.7	681.9	704.7	341.0	575.1	7,803.7
7. RSH	0.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.8	40.8
8. UH	39.3	34.3	39.3	38.1	39.3	38.1	39.3	39.3	38.1	39.3	379.0	152.1	915.5
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	120.0	480.0
10. FOH & PFOH	23.6	20.6	23.6	22.9	23.6	22.9	23.6	23.6	22.9	23.6	11.4	19.3	261.5
11. MOH & PMOH	29.8	25.9	29.8	28.8	29.8	28.8	29.8	29.8	28.8	29.8	14.4	24.3	329.8
12. Oper. Btu(MBtu)	3,824,587	3,418,526	3,916,962	3,974,579	3,962,268	4,139,132	4,027,180	4,188,607	4,160,838	3,979,505	1,811,497	3,107,177	44,523,280
13. Net Gen. (MWH)	370,021.0	331,877.0	380,161.0	388,318.0	385,161.0	406,850.0	392,356.0	410,412.0	409,314.0	387,068.0	174,778.0	300,435.0	4,336,751.0
14. ANOHR (Btu/KWH)	10,336	10,301	10,303	10,235	10,287	10,174	10,264	10,206	10,165	10,281	10,365	10,342	10,267
15. NOF (%)	73.7	75.9	75.8	80.0	76.8	83.8	78.2	81.8	84.3	77.1	72.0	73.4	78.1
16. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
17. ANOHR Equation	ANOHR=	-16.182 x NOF +		11,529.6									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.85	71.32	52.01	94.85	94.85	94.85	94.85	94.85	94.85	94.85	94.85	94.85	89.40
2. POF	0.00	25.00	45.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.75
3. EUOF	5.15	3.68	2.83	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	4.84
4. EUOR	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	718.5	463.5	394.0	695.3	718.5	695.3	718.5	718.5	695.3	718.5	695.3	718.5	7,949.6
7. RSH	0.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.0
8. UH	25.5	184.5	350.0	24.7	25.5	24.7	25.5	25.5	24.7	25.5	24.7	25.5	786.4
9. POH & PPOH	0.0	168.0	336.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0
10. FOH & PFOH	21.4	13.8	11.8	20.7	21.4	20.7	21.4	21.4	20.7	21.4	20.7	21.4	237.2
11. MOH & PMOH	16.9	10.9	9.3	16.4	16.9	16.4	16.9	16.9	16.4	16.9	16.4	16.9	187.0
12. Oper. Btu(MBtu)	4,055,761	2,686,777	2,243,566	3,693,629	3,798,722	3,987,170	3,967,322	4,005,905	3,892,272	3,850,219	4,177,231	4,174,505	44,548,737
13. Net Gen. (MWH)	395,160.0	263,242.0	218,990.0	355,619.0	365,416.0	389,756.0	384,823.0	389,319.0	378,583.0	371,303.0	412,551.0	409,217.0	4,333,979.0
14. ANOHR (Btu/KWH)	10,264	10,206	10,245	10,386	10,396	10,230	10,309	10,290	10,281	10,369	10,125	10,201	10,279
15. NOF (%)	77.5	80.0	78.3	72.0	71.6	79.0	75.4	76.3	76.7	72.8	83.6	80.2	76.8
16. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
17. ANOHR Equation	ANOHR=	-22.641 x NOF +		12,017.5									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.20	95.13	72.94	95.36	95.73	95.26	95.32	95.26	95.26	95.46	0.00	59.70	82.65
2. POF	0.00	1.79	22.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	38.71	13.56
3. EUOF	3.80	3.09	4.48	4.64	4.27	4.74	4.68	4.74	4.74	4.54	0.00	1.59	3.78
4. EUOR	4.74	4.74	4.74	4.74	4.74	4.74	4.74	4.74	4.74	4.74	0.00	4.74	4.74
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	576.5	422.9	680.3	681.6	647.6	696.2	710.8	719.4	696.2	689.2	0.0	241.8	6,762.6
7. RSH	147.8	234.6	40.5	15.1	74.3	0.0	8.9	0.0	0.0	31.2	0.0	205.9	758.3
8. UH	19.7	14.5	23.2	23.3	22.1	23.8	24.3	24.6	23.8	23.6	720.0	296.3	1239.1
9. POH & PPOH	0.0	12.0	168.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	720.0	288.0	1188.0
10. FOH & PFOH	16.0	11.7	18.8	18.9	17.9	19.3	19.7	19.9	19.3	19.1	0.0	6.7	187.2
11. MOH & PMOH	12.3	9.0	14.5	14.5	13.8	14.9	15.2	15.4	14.9	14.7	0.0	5.2	144.3
12. Oper. Btu(MBtu)	1,808,292	1,329,349	1,698,031	1,969,965	1,710,855	2,061,444	2,144,202	2,139,032	2,049,808	1,884,681	-	740,524	19,555,224
13. Net Gen. (MWH)	248,796.0	182,980.0	224,292.0	266,642.0	227,984.0	280,312.0	292,637.0	291,098.0	278,425.0	252,588.0	-	101,373.0	2,647,127.0
14. ANOHR (Btu/KWH)	7,268	7,265	7,571	7,388	7,504	7,354	7,327	7,348	7,362	7,461	-	7,305	7,387
15. NOF (%)	93.4	93.6	71.4	84.7	76.2	87.1	89.1	87.6	86.6	79.3	0.0	90.7	84.7
16. NSC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
17. ANOHR Equation	ANOHR=	-13.720 x NOF +		8,549.8									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Hines 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.05	96.93	85.86	83.49	96.68	96.53	96.58	96.54	96.56	9.37	96.85	96.75	87.29
2. POF	0.00	0.00	11.29	13.33	0.00	0.00	0.00	0.00	0.00	90.32	0.00	0.00	9.73
3. EUOF	2.95	3.07	2.85	3.17	3.32	3.47	3.42	3.46	3.44	0.30	3.15	3.25	2.98
4. EUOR	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	606.9	571.5	586.2	632.1	682.2	690.4	702.9	712.4	685.1	62.6	627.1	669.7	7,229.0
7. RSH	127.3	91.3	148.3	77.7	50.8	18.5	29.8	20.1	23.8	8.4	82.8	63.5	742.3
8. UH	9.8	9.2	9.5	10.2	11.0	11.1	11.3	11.5	11.1	673.0	10.1	10.8	788.7
9. POH & PPOH	0.0	0.0	84.0	96.0	0.0	0.0	0.0	0.0	0.0	672.0	0.0	0.0	852.0
10. FOH & PFOH	7.7	7.2	7.4	8.0	8.6	8.7	8.9	9.0	8.7	0.8	7.9	8.5	91.4
11. MOH & PMOH	14.3	13.4	13.8	14.9	16.0	16.2	16.5	16.7	16.1	1.5	14.7	15.7	169.9
12. Oper. Btu(MBtu)	1,515,112	1,436,130	1,503,698	1,547,336	1,933,506	2,016,483	1,996,257	2,075,826	1,988,134	162,012	1,754,369	1,769,818	19,703,500
13. Net Gen. (MWH)	209,096.0	198,263.0	207,812.0	213,332.0	268,704.0	280,744.0	277,459.0	288,963.0	276,686.0	22,401.0	243,623.0	244,981.0	2,732,064.0
14. ANOHR (Btu/KWH)	7,246	7,244	7,236	7,253	7,196	7,183	7,195	7,184	7,186	7,232	7,201	7,224	7,212
15. NOF (%)	70.3	70.8	72.3	68.9	80.4	83.0	80.6	82.8	82.4	73.0	79.3	74.7	77.1
16. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
17. ANOHR Equation	ANOHR=	-4.998 x NOF +		7,597.4									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Hines 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	99.62	99.58	32.13	99.49	99.52	99.49	99.49	99.49	81.16	94.66	87.84	99.49	90.91
2. POF	0.00	0.00	67.74	0.00	0.00	0.00	0.00	0.00	18.33	4.84	11.67	0.00	8.63
3. EUOF	0.38	0.42	0.12	0.51	0.48	0.51	0.51	0.51	0.50	0.50	0.50	0.51	0.46
4. EUOR	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	535.3	545.0	178.3	704.6	690.6	706.9	731.2	727.8	695.2	714.3	687.5	734.0	7,650.9
7. RSH	207.6	125.9	61.3	14.0	52.0	11.7	11.3	14.7	23.4	28.3	31.1	8.5	589.8
8. UH	1.1	1.1	504.4	1.4	1.4	1.4	1.5	1.5	1.4	1.4	1.4	1.5	519.3
9. POH & PPOH	0.0	0.0	504.0	0.0	0.0	0.0	0.0	0.0	132.0	36.0	84.0	0.0	756.0
10. FOH & PFOH	1.1	1.1	0.4	1.4	1.4	1.4	1.5	1.4	1.4	1.4	1.4	1.5	15.2
11. MOH & PMOH	1.7	1.8	0.6	2.3	2.2	2.3	2.4	2.3	2.2	2.3	2.2	2.4	24.7
12. Oper. Btu(MBtu)	1,564,039	1,667,293	533,355	2,089,315	2,051,595	2,221,425	2,278,909	2,258,002	1,805,744	2,083,927	1,946,810	2,261,141	22,771,262
13. Net Gen. (MWH)	213,253.0	228,878.0	72,968.0	285,482.0	280,402.0	306,225.0	313,737.0	310,637.0	242,444.0	284,082.0	264,289.0	310,728.0	3,113,125.0
14. ANOHR (Btu/KWH)	7,334	7,285	7,309	7,319	7,317	7,254	7,264	7,269	7,448	7,336	7,366	7,277	7,315
15. NOF (%)	81.6	86.1	83.8	83.0	83.2	88.8	87.9	87.5	71.5	81.5	78.8	86.7	83.4
16. NSC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
17. ANOHR Equation	ANOHR=	-11.200 x NOF +		8,248.5									

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

Original Sheet No. 7.107.1

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2014 - December 2014

PLANT/UNIT **Hines 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.22	98.28	88.72	39.32	98.23	98.22	98.22	98.22	98.22	98.24	83.23	86.94	90.39
2. POF	0.00	0.00	9.68	60.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	11.29	7.95
3. EUOF	1.78	1.72	1.60	0.68	1.77	1.78	1.78	1.78	1.78	1.76	1.77	1.77	1.67
4. EUOR	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	736.4	642.1	664.0	274.6	734.5	711.8	737.2	737.0	712.8	731.2	711.0	734.8	8,127.3
7. RSH	0.8	24.0	1.9	10.9	2.7	1.6	0.0	0.2	0.6	6.0	2.4	2.4	53.5
8. UH	6.8	5.9	78.1	434.5	6.8	6.6	6.8	6.8	6.6	6.8	6.6	6.8	579.2
9. POH & PPOH	0.0	0.0	72.0	432.0	0.0	0.0	0.0	0.0	0.0	0.0	108.0	84.0	696.0
10. FOH & PFOH	11.0	9.6	9.9	4.1	10.9	10.6	11.0	11.0	10.6	10.9	10.6	10.9	121.0
11. MOH & PMOH	2.3	2.0	2.0	0.8	2.3	2.2	2.3	2.3	2.2	2.2	2.2	2.3	24.9
12. Oper. Btu(MBtu)	2,101,722	1,992,417	1,979,825	824,075	2,145,895	2,186,659	2,250,213	2,246,067	2,204,721	2,209,586	1,838,869	1,885,172	23,870,342
13. Net Gen. (MWH)	303,223.0	288,765.0	286,302.0	119,212.0	309,976.0	316,735.0	325,824.0	325,195.0	319,475.0	319,761.0	264,023.0	270,571.0	3,449,062.0
14. ANOHR (Btu/KWH)	6,931	6,900	6,915	6,913	6,923	6,904	6,906	6,907	6,901	6,910	6,965	6,967	6,921
15. NOF (%)	87.2	95.3	91.4	92.0	89.4	94.3	93.6	93.5	95.0	92.6	78.7	78.0	89.9
16. NSC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
17. ANOHR Equation	ANOHR=	-3.914 x NOF +		7,272.7									

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

PLANNED OUTAGE SCHEDULES

Duke Energy Florida
Period of: January 2014 - December 2014

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow 4	03/29 (0001) - 04/26 (2400)	Balance of Plant, Combustion Turbine & Steam Turbine Inspection
Bartow 4	11/17 (0001) - 12/12 (2400)	Balance of Plant, Combustion Turbine Inspection
Crystal River 4	11/16 (0001) - 12/05 (2400)	Balance of Plant
Crystal River 5	02/22 (0001) - 03/14 (2400)	Balance of Plant
Hines 1	02/28 (0001) - 03/07 (2400)	Combustion Turbine Inspection
Hines 1	3/14 (0001) - 3/21 (2400)	Combustion Turbine Inspection
Hines 1	11/1 (0001) - 12/12 (2400)	Generator Rotor Maintinence, Turbine Valve Maintinence
Hines 2	03/22 (0001) - 03/28 (2400)	Combustion Turbine Inspection
Hines 2	4/19 (0001) - 4/26 (2400)	Combustion Turbine Inspection
Hines 2	10/04 (0001) - 10/31 (2400)	Balance of Plant, Major Inspection
Hines 3	03/01 (0001) - 03/21 (2400)	Balance of Plant, Combustion Turbine Inspection
Hines 3	9/20 (0001) - 10/03 (2400)	Combustion Turbine Inspection
Hines 3	11/16 (0001) - 11/22 (2400)	Combustion Turbine Inspection
Hines 4	03/29 (0001) - 04/18 (2400)	Balance of Plant, Turbine Valve Maintinence
Hines 4	11/06 (0001) - 11/14 (2400)	Combustion Turbine Inspection
Hines 4	12/06 (0001) - 12/12 (2400)	Combustion Turbine Inspection

Issued by: Duke Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

AVERAGE NET OPERATING HEAT RATE CURVES

DUKE ENERGY FLORIDA

Bartow Unit 4

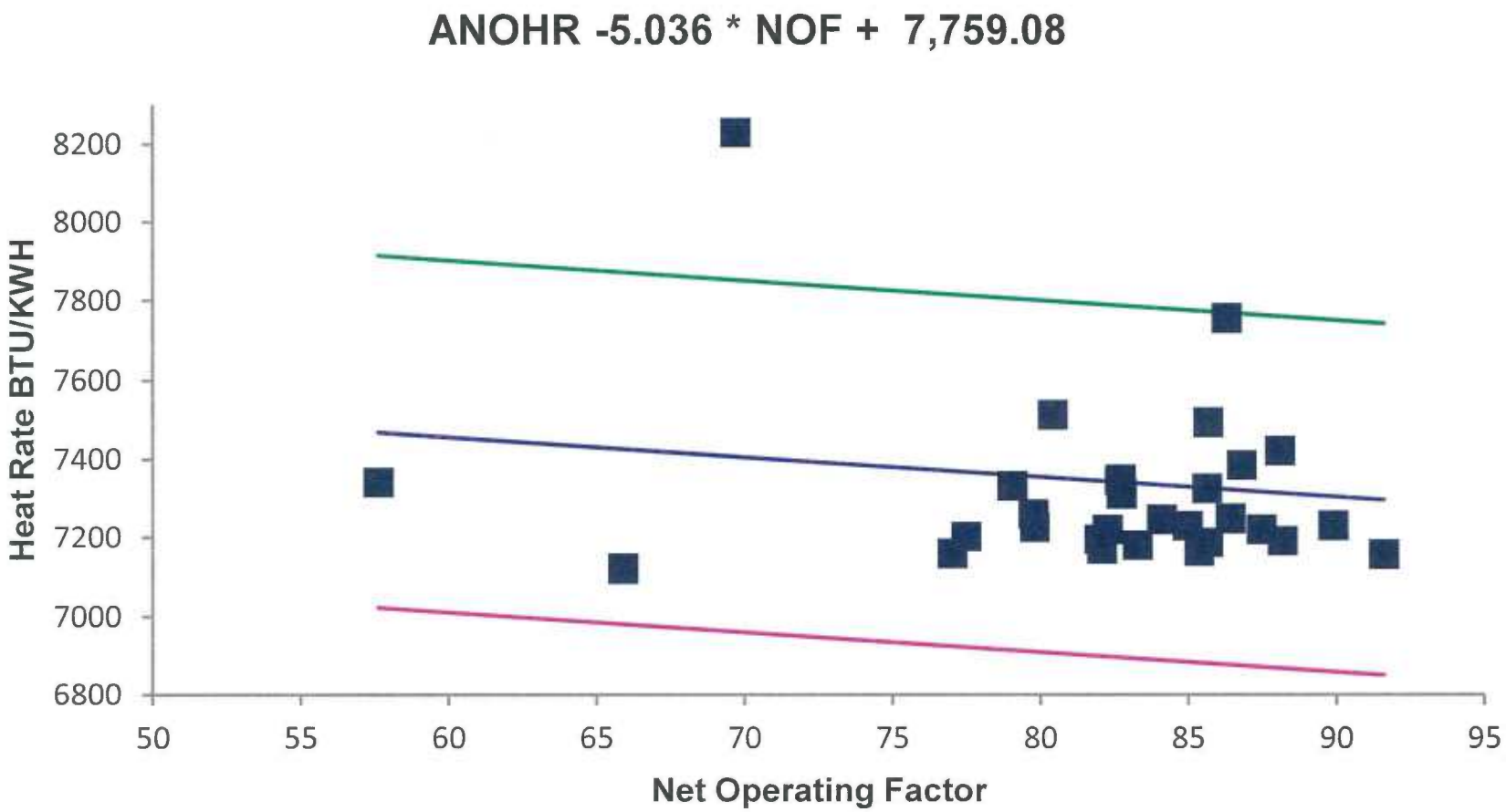
ANOHR -5.036 * NOF + 7,759.08

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	69.7	8,230	7,408	822.3	445.3
Aug-10	83.3	7,181	7,340	-158.3	445.3
Sep-10	82.3	7,221	7,345	-123.4	445.3
Oct-10	65.9	7,121	7,427	-305.8	445.3
Nov-10	57.6	7,341	7,469	-127.7	445.3
Dec-10	79.8	7,227	7,357	-129.9	445.3
Jan-11	77.5	7,204	7,369	-165.2	445.3
Feb-11	77.0	7,160	7,371	-210.7	445.3
Mar-11	80.4	7,514	7,354	159.6	445.3
Apr-11	88.1	7,423	7,315	107.4	445.3
May-11	85.7	7,495	7,328	167.2	445.3
Jun-11	84.1	7,247	7,336	-88.5	445.3
Jul-11	86.3	7,756	7,324	431.3	445.3
Aug-11	87.5	7,222	7,319	-96.8	445.3
Sep-11	82.7	7,312	7,342	-30.1	445.3
Oct-11	85.0	7,230	7,331	-100.8	445.3
Nov-11	89.9	7,231	7,306	-74.9	445.3
Dec-11	91.6	7,158	7,298	-139.6	445.3
Jan-12	88.2	7,192	7,315	-122.8	445.3
Feb-12	85.7	7,188	7,328	-139.7	445.3
May-12	86.4	7,249	7,324	-74.5	445.3
Jun-12	79.0	7,333	7,361	-28.2	445.3
Jul-12	82.7	7,346	7,343	3.6	445.3
Aug-12	85.4	7,167	7,329	-162.6	445.3
Sep-12	82.7	7,350	7,343	7.4	445.3
Oct-12	82.1	7,172	7,346	-173.8	445.3
Nov-12	79.8	7,260	7,357	-97.0	445.3
Dec-12	82.0	7,196	7,346	-150.4	445.3
Jan-13	85.6	7,326	7,328	-1.5	445.3
Feb-13	86.8	7,386	7,322	64.2	445.3
Mar-13	84.0	8,365	7,336	1029.1	445.3
Apr-13	82.5	7,324	7,344	-19.4	445.3
May-13	83.9	7,276	7,336	-60.5	445.3
Jun-13	88.3	7,305	7,314	-9.7	445.3

Regression Output:

Constant	7759.08
Std Err of Y Est	274.7760925
R Squared	0.015534326
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-5.036285823
Std Err of Coef.	7.087441031


ANOHR -5.036 * NOF + 7,759.08
Heat Rate BTU/KWH
8200
8000
7800
7600
7400
7200
7000
6800
50
55
60
65
70
75
80
85
90
95
Net Operating Factor

DUKE ENERGY FLORIDA

Crystal River Unit 4

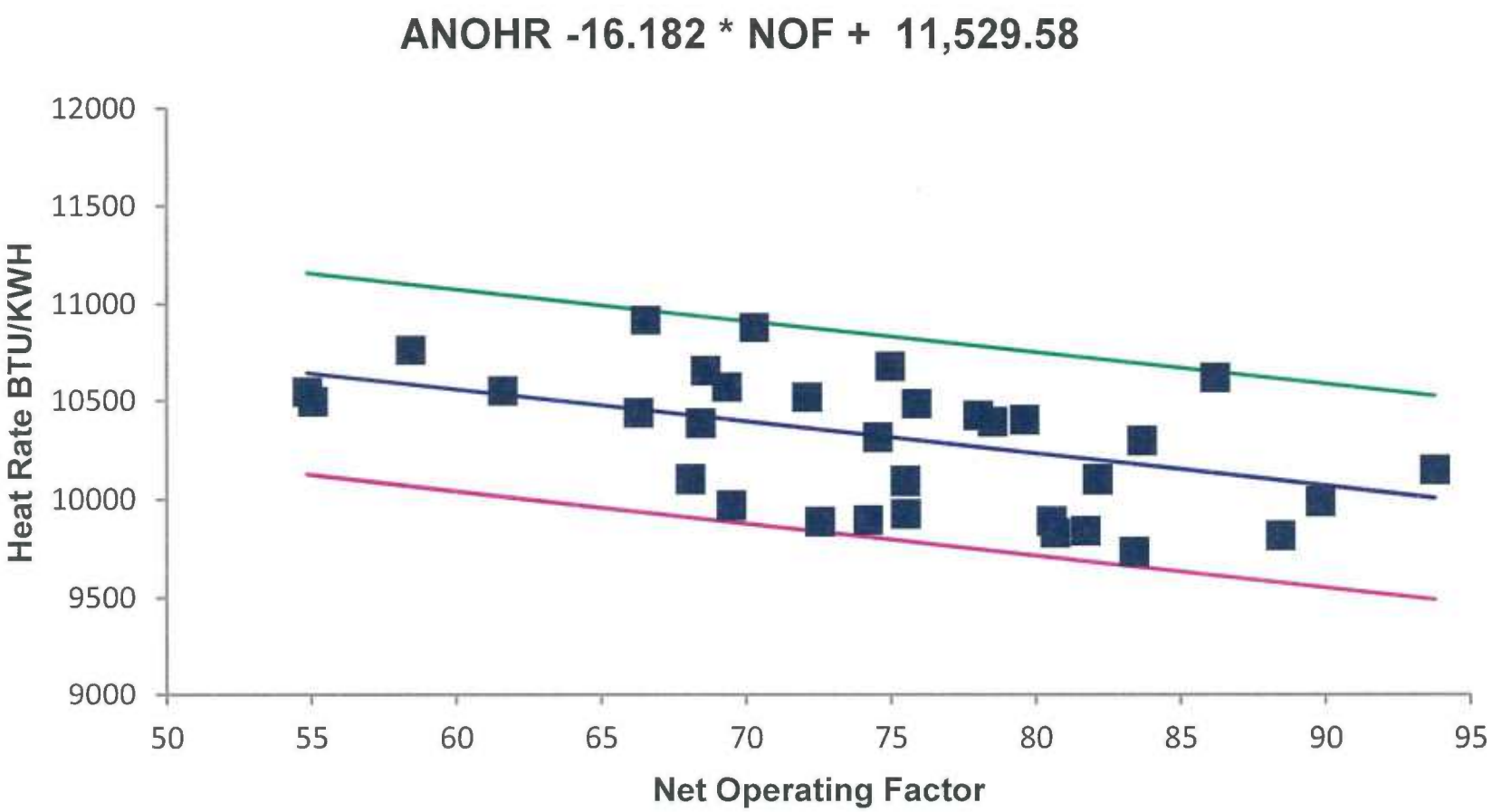
ANOHR -16.182 * NOF + 11,529.58

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	89.8	9,992	10,076	-84.1	516.7
Aug-10	83.7	10,298	10,176	122.1	516.7
Sep-10	66.5	10,916	10,453	463.3	516.7
Oct-10	68.1	10,103	10,428	-324.5	516.7
Nov-10	75.5	10,094	10,308	-214.0	516.7
Dec-10	83.4	9,738	10,180	-442.4	516.7
Jan-11	72.5	9,890	10,356	-465.7	516.7
Feb-11	72.1	10,519	10,363	156.2	516.7
Mar-11	74.2	9,897	10,329	-431.5	516.7
Apr-11	88.4	9,820	10,099	-278.1	516.7
May-11	93.8	10,151	10,012	138.7	516.7
Jun-11	80.7	9,832	10,224	-392.2	516.7
Jul-11	80.5	9,893	10,226	-333.6	516.7
Aug-11	81.7	9,844	10,207	-363.4	516.7
Sep-11	75.5	9,929	10,308	-379.0	516.7
Oct-11	69.5	9,971	10,405	-434.1	516.7
Dec-11	55.0	10,496	10,639	-142.8	516.7
Jan-12	54.9	10,545	10,642	-97.4	516.7
Feb-12	58.4	10,761	10,584	176.8	516.7
Mar-12	75.9	10,486	10,302	184.1	516.7
Apr-12	78.0	10,426	10,267	158.5	516.7
May-12	74.5	10,316	10,323	-7.7	516.7
Jun-12	70.3	10,878	10,392	485.9	516.7
Jul-12	78.5	10,394	10,259	134.2	516.7
Aug-12	75.0	10,678	10,316	361.4	516.7
Sep-12	68.6	10,655	10,419	235.7	516.7
Oct-12	79.6	10,404	10,241	162.3	516.7
Nov-12	82.1	10,102	10,201	-98.3	516.7
Dec-12	69.3	10,571	10,408	163.2	516.7
Jan-13	66.3	10,439	10,457	-17.8	516.7
Feb-13	68.4	10,387	10,422	-35.6	516.7
Mar-13	61.6	10,551	10,533	18.3	516.7
Apr-13	86.2	10,620	10,135	484.8	516.7
May-13	80.5	10,938	10,227	711.0	516.7
Jun-13	80.9	10,606	10,220	385.7	516.7

Regression Output:

Constant	11529.58
Std Err of Y Est	318.6752785
R Squared	0.186180414
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-16.18243579
Std Err of Coef.	5.889575529


ANOHR -16.182 * NOF + 11,529.58
Heat Rate BTU/KWH
12000
11500
11000
10500
10000
9500
9000
50
55
60
65
70
75
80
85
90
95
Net Operating Factor

DUKE ENERGY FLORIDA

Crystal River Unit 5

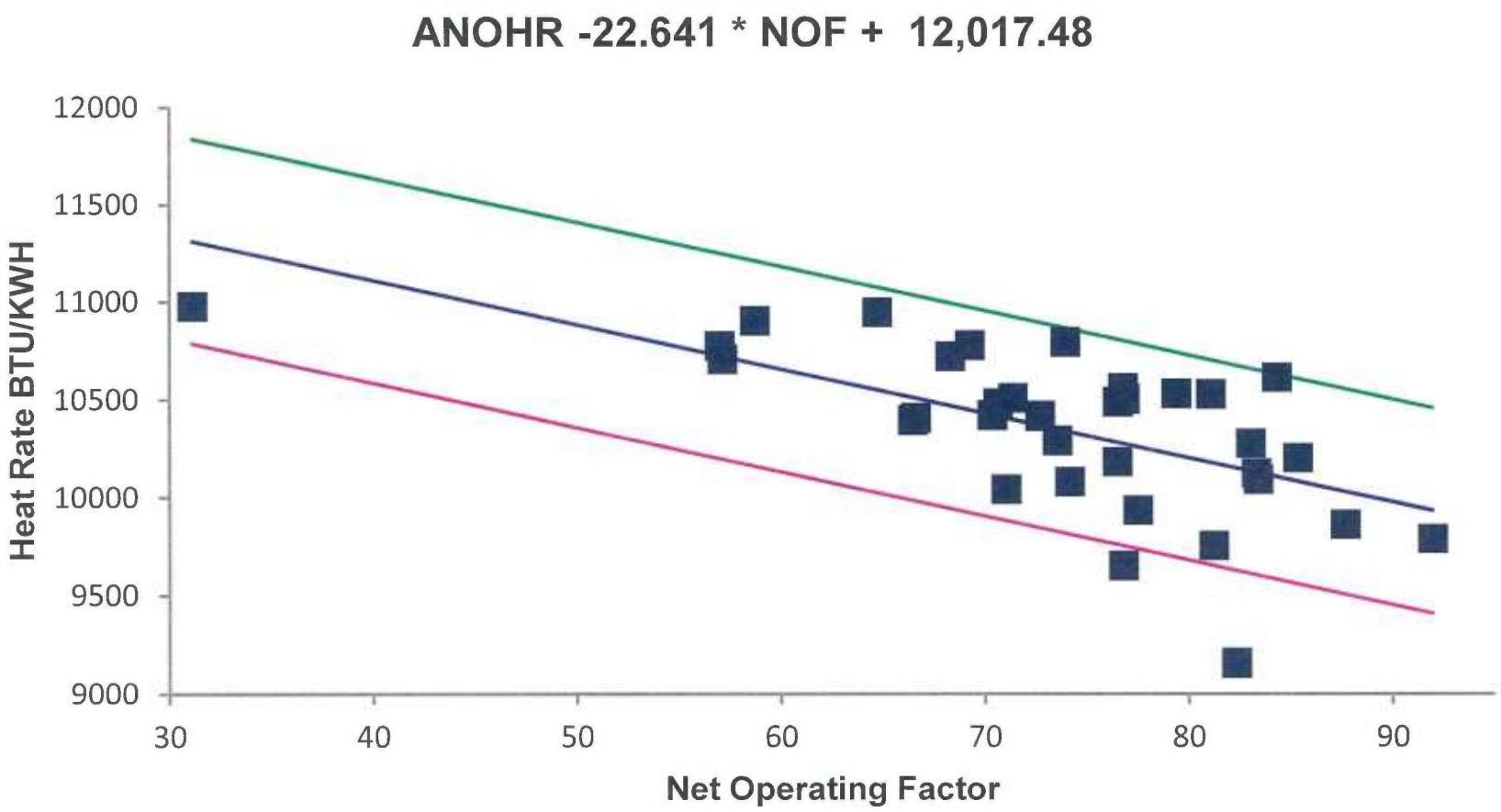
ANOHR -22.641 * NOF + 12,017.48

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	91.9	9,789	9,936	-146.3	525.2
Aug-10	84.3	10,616	10,109	507.7	525.2
Sep-10	72.7	10,420	10,372	48.7	525.2
Oct-10	71.0	10,043	10,409	-366.2	525.2
Nov-10	76.8	9,652	10,279	-626.7	525.2
Dec-10	83.4	10,095	10,129	-33.8	525.2
Jan-11	76.5	10,491	10,285	205.9	525.2
Feb-11	77.5	9,937	10,263	-325.5	525.2
Mar-11	74.1	10,084	10,339	-254.8	525.2
Apr-11	87.7	9,863	10,032	-169.6	525.2
May-11	82.3	9,157	10,153	-995.8	525.2
Jun-11	83.0	10,280	10,137	142.7	525.2
Jul-11	83.3	10,126	10,131	-5.2	525.2
Aug-11	81.2	9,754	10,179	-424.5	525.2
Sep-11	73.6	10,294	10,352	-58.4	525.2
Oct-11	57.0	10,777	10,727	49.3	525.2
Nov-11	76.5	10,185	10,286	-100.4	525.2
Dec-11	69.3	10,781	10,449	331.5	525.2
Jan-12	31.1	10,978	11,313	-334.4	525.2
Feb-12	58.7	10,905	10,688	216.9	525.2
Mar-12	71.4	10,510	10,402	107.9	525.2
Apr-12	70.6	10,484	10,418	65.5	525.2
May-12	66.5	10,398	10,513	-115.2	525.2
Jun-12	64.7	10,948	10,552	395.5	525.2
Jul-12	76.8	10,563	10,279	283.9	525.2
Aug-12	73.9	10,798	10,343	454.4	525.2
Sep-12	68.3	10,724	10,471	252.8	525.2
Oct-12	70.4	10,424	10,424	-0.6	525.2
Jan-13	57.1	10,709	10,724	-14.8	525.2
Feb-13	66.6	10,409	10,509	-100.0	525.2
Mar-13	85.3	10,205	10,085	119.9	525.2
Apr-13	81.1	10,531	10,182	348.8	525.2
May-13	79.4	10,534	10,220	313.3	525.2
Jun-13	76.8	10,505	10,278	227.3	525.2

Regression Output:

Constant	12017.48
Std Err of Y Est	324.0939432
R Squared	0.389560717
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-22.64111859
Std Err of Coef.	5.010217151


ANOHR -22.641 * NOF + 12,017.48
Heat Rate BTU/KWH
12000
11500
11000
10500
10000
9500
9000
30
40
50
60
70
80
90
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 1

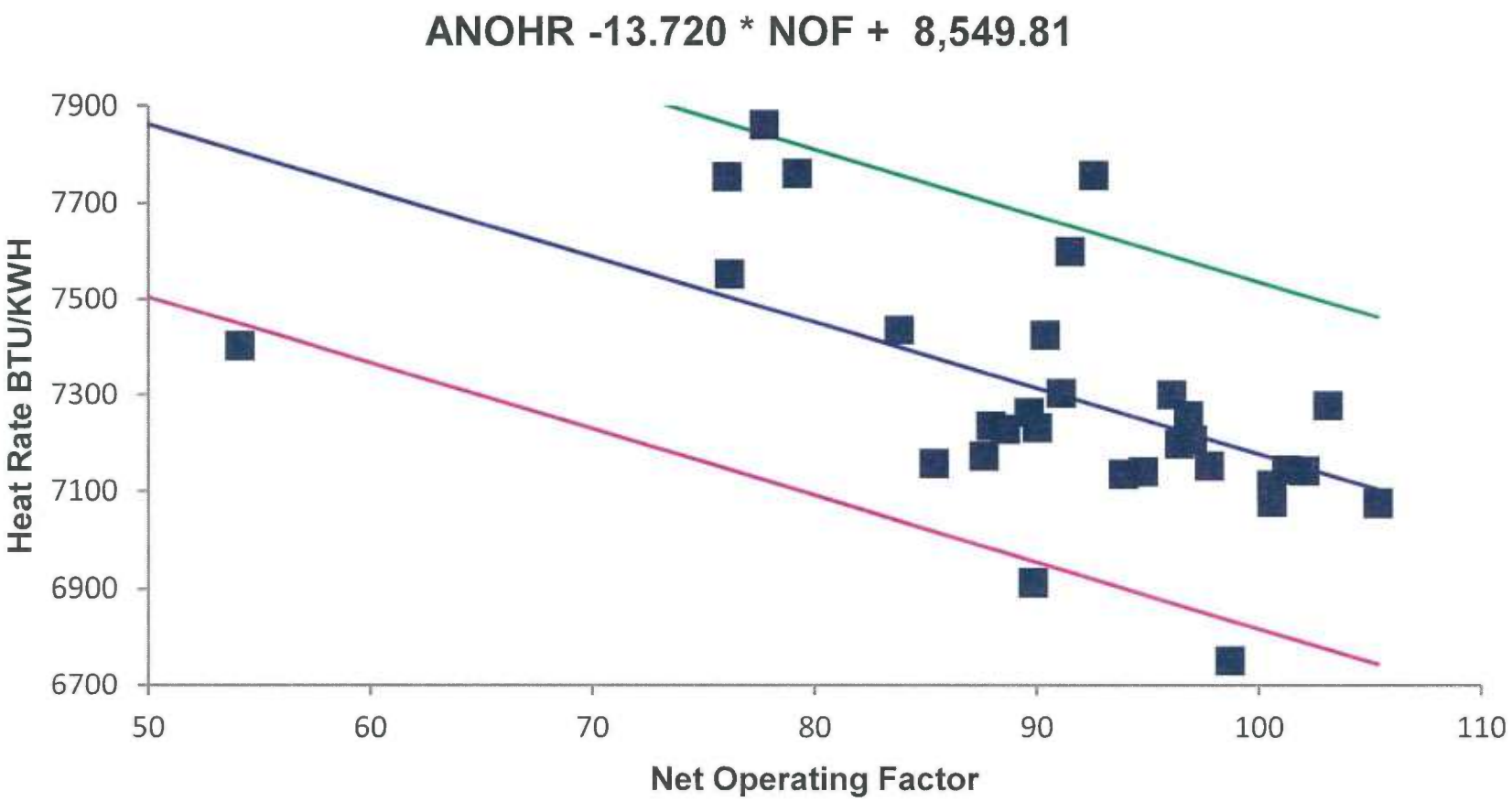
ANOHR -13.720 * NOF + 8,549.81

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	85.4	7,158	7,378	-220.6	359.3
Aug-10	76.1	7,756	7,506	249.3	359.3
Sep-10	97.8	7,153	7,208	-55.5	359.3
Oct-10	87.6	7,173	7,348	-174.6	359.3
Nov-10	103.1	7,278	7,135	143.0	359.3
Dec-10	93.9	7,136	7,261	-125.8	359.3
Jan-11	87.9	7,236	7,343	-107.3	359.3
Feb-11	54.1	7,402	7,807	-405.3	359.3
Mar-11	101.2	7,145	7,161	-16.2	359.3
Jun-11	83.8	7,435	7,400	35.1	359.3
Jul-11	94.8	7,141	7,249	-108.6	359.3
Aug-11	91.1	7,304	7,300	4.2	359.3
Sep-11	88.6	7,229	7,334	-105.0	359.3
Oct-11	96.1	7,301	7,232	69.3	359.3
Nov-11	98.7	6,752	7,196	-444.0	359.3
Dec-11	105.3	7,077	7,104	-27.3	359.3
Jan-12	89.8	6,914	7,317	-403.7	359.3
Feb-12	102.1	7,143	7,149	-6.6	359.3
Mar-12	100.6	7,113	7,170	-56.4	359.3
Apr-12	96.4	7,199	7,227	-28.2	359.3
May-12	76.2	7,553	7,505	48.0	359.3
Jun-12	90.4	7,425	7,310	114.9	359.3
Jul-12	89.6	7,264	7,320	-56.3	359.3
Aug-12	92.6	7,758	7,280	478.2	359.3
Sep-12	96.8	7,258	7,221	36.4	359.3
Oct-12	91.5	7,600	7,294	305.2	359.3
Nov-12	78.0	7,955	7,479	475.6	359.3
Dec-12	90.0	7,232	7,315	-82.8	359.3
Jan-13	97.0	7,207	7,219	-11.8	359.3
Feb-13	100.6	7,080	7,170	-90.3	359.3
Mar-13	77.7	7,862	7,483	378.9	359.3
Apr-13	40.0	7,962	8,001	-38.8	359.3
May-13	47.3	7,829	7,901	-72.0	359.3
Jun-13	79.2	7,762	7,463	298.8	359.3

Regression Output:

Constant	8549.81
Std Err of Y Est	221.726288
R Squared	0.474895594
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-13.720371
Std Err of Coef.	2.550437157


ANOHR -13.720 * NOF + 8,549.81
Heat Rate BTU/KWH
7900
7700
7500
7300
7100
6900
6700
50
60
70
80
90
100
110
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 2

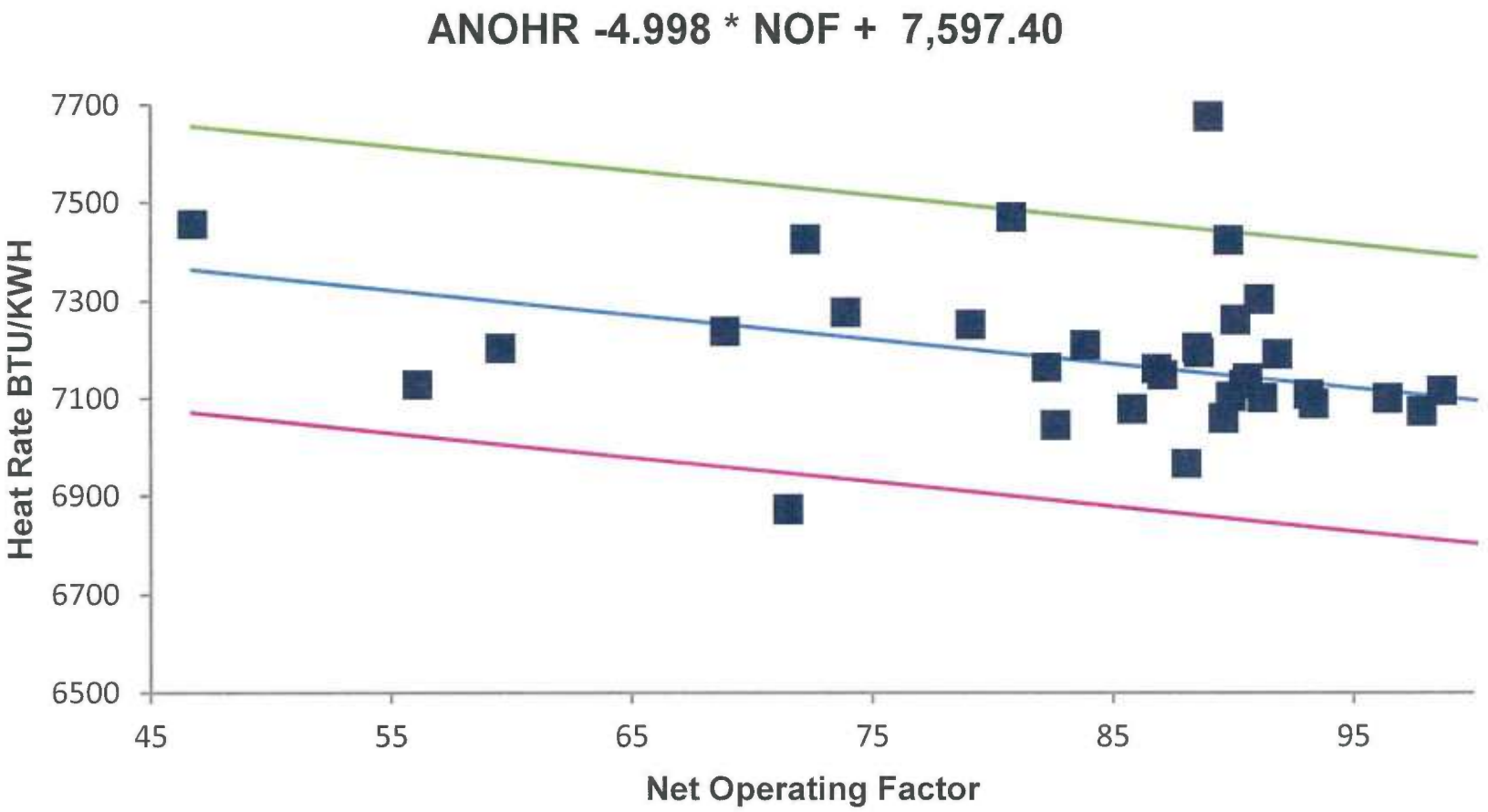
ANOHR -4.998 * NOF + 7,597.40

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	88.5	7,206	7,155	50.4	292.5
Aug-10	89.8	7,424	7,149	275.5	292.5
Sep-10	93.1	7,110	7,132	-22.4	292.5
Oct-10	82.2	7,165	7,186	-21.3	292.5
Nov-10	68.9	7,239	7,253	-14.4	292.5
Dec-10	91.8	7,192	7,138	53.8	292.5
Jan-11	73.9	7,278	7,228	49.6	292.5
Feb-11	83.9	7,211	7,178	32.7	292.5
Apr-11	56.1	7,129	7,317	-187.7	292.5
May-11	90.6	7,143	7,145	-2.1	292.5
Jun-11	86.8	7,162	7,164	-1.1	292.5
Jul-11	85.8	7,079	7,169	-89.2	292.5
Aug-11	91.1	7,305	7,142	162.3	292.5
Sep-11	90.5	7,130	7,145	-15.5	292.5
Oct-11	91.2	7,102	7,142	-39.2	292.5
Nov-11	101.7	6,578	7,089	-510.5	292.5
Dec-11	88.6	7,196	7,155	41.0	292.5
Jan-12	82.6	7,047	7,184	-137.9	292.5
Feb-12	72.2	7,426	7,236	189.2	292.5
Mar-12	98.7	7,117	7,104	12.9	292.5
Apr-12	96.4	7,102	7,116	-14.0	292.5
May-12	97.8	7,075	7,109	-33.3	292.5
Jun-12	89.9	7,105	7,148	-43.2	292.5
Jul-12	87.1	7,149	7,162	-12.9	292.5
Aug-12	89.6	7,061	7,150	-88.8	292.5
Sep-12	93.3	7,090	7,131	-40.7	292.5
Oct-12	88.1	6,967	7,157	-189.9	292.5
Nov-12	90.1	7,263	7,147	115.5	292.5
Dec-12	59.5	7,204	7,300	-95.5	292.5
Jan-13	46.7	7,456	7,364	91.8	292.5
Mar-13	71.5	6,874	7,240	-366.6	292.5
Apr-13	79.1	7,253	7,202	50.8	292.5
May-13	80.8	7,471	7,194	276.9	292.5
Jun-13	89.0	7,676	7,153	523.7	292.5

Regression Output:

Constant	7597.40
Std Err of Y Est	180.4787155
R Squared	0.106280044
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-4.997534758
Std Err of Coef.	2.561861813


ANOHR -4.998 * NOF + 7,597.40
Heat Rate BTU/KWH
7700
7500
7300
7100
6900
6700
6500
45
55
65
75
85
95
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 3

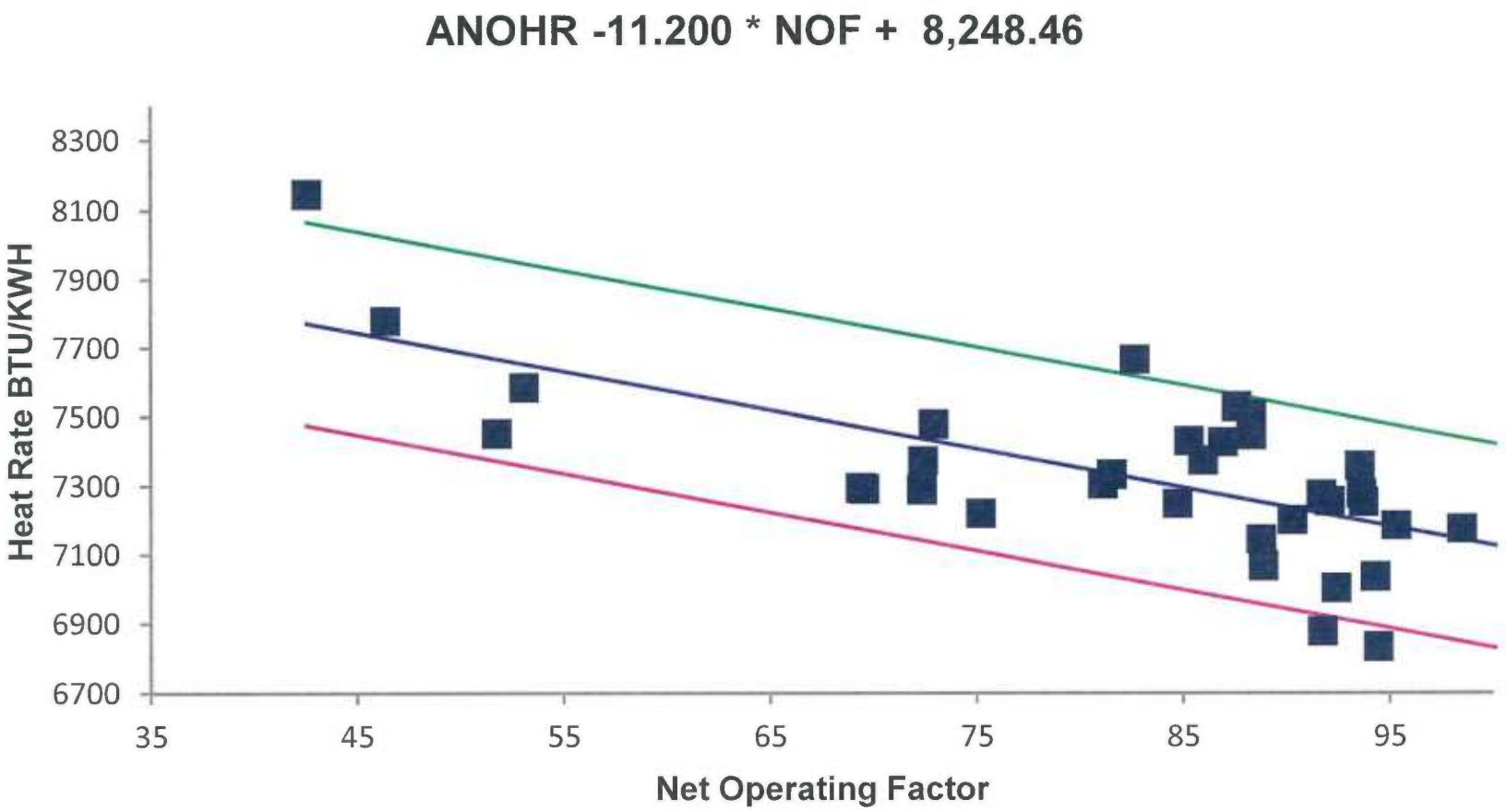
ANOHR -11.200 * NOF + 8,248.46

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	98.5	7,176	7,145	30.9	295.6
Aug-10	94.4	6,835	7,191	-355.8	295.6
Sep-10	92.1	7,257	7,217	39.9	295.6
Oct-10	69.6	7,292	7,469	-177.5	295.6
Nov-10	42.6	8,147	7,772	375.3	295.6
Dec-10	72.9	7,479	7,432	47.2	295.6
Jan-11	81.1	7,307	7,340	-33.6	295.6
Feb-11	75.2	7,221	7,406	-185.5	295.6
Mar-11	95.3	7,185	7,181	4.4	295.6
Apr-11	94.3	7,038	7,192	-154.5	295.6
May-11	87.6	7,530	7,267	262.3	295.6
Jun-11	90.3	7,201	7,237	-36.1	295.6
Jul-11	88.3	7,448	7,260	188.6	295.6
Aug-11	91.7	6,879	7,221	-342.0	295.6
Sep-11	93.6	7,278	7,200	77.8	295.6
Oct-11	92.4	7,005	7,213	-208.2	295.6
Nov-11	102.1	7,309	7,105	203.6	295.6
Dec-11	86.0	7,374	7,286	88.4	295.6
Jan-12	72.4	7,372	7,438	-65.3	295.6
Feb-12	88.8	7,145	7,254	-109.4	295.6
Apr-12	72.3	7,290	7,438	-148.7	295.6
May-12	91.7	7,275	7,222	53.3	295.6
Jun-12	93.7	7,254	7,199	55.3	295.6
Jul-12	88.3	7,506	7,259	246.8	295.6
Aug-12	88.9	7,069	7,253	-184.2	295.6
Sep-12	93.5	7,358	7,201	157.3	295.6
Oct-12	82.7	7,667	7,323	344.5	295.6
Nov-12	86.9	7,427	7,275	152.3	295.6
Dec-12	81.6	7,333	7,335	-1.7	295.6
Jan-13	51.8	7,452	7,669	-217.0	295.6
Feb-13	53.1	7,585	7,654	-69.0	295.6
Mar-13	46.4	7,779	7,729	49.8	295.6
Apr-13	69.4	7,295	7,471	-176.3	295.6
May-13	85.3	7,430	7,293	137.1	295.6
Jun-13	84.7	7,250	7,299	-49.8	295.6

Regression Output:

Constant	8248.46
Std Err of Y Est	182.3194092
R Squared	0.461611059
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-11.20007188
Std Err of Coef.	2.105589969


ANOHR -11.200 * NOF + 8,248.46
Heat Rate BTU/KWH
8300
8100
7900
7700
7500
7300
7100
6900
6700
35
45
55
65
75
85
95
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 4

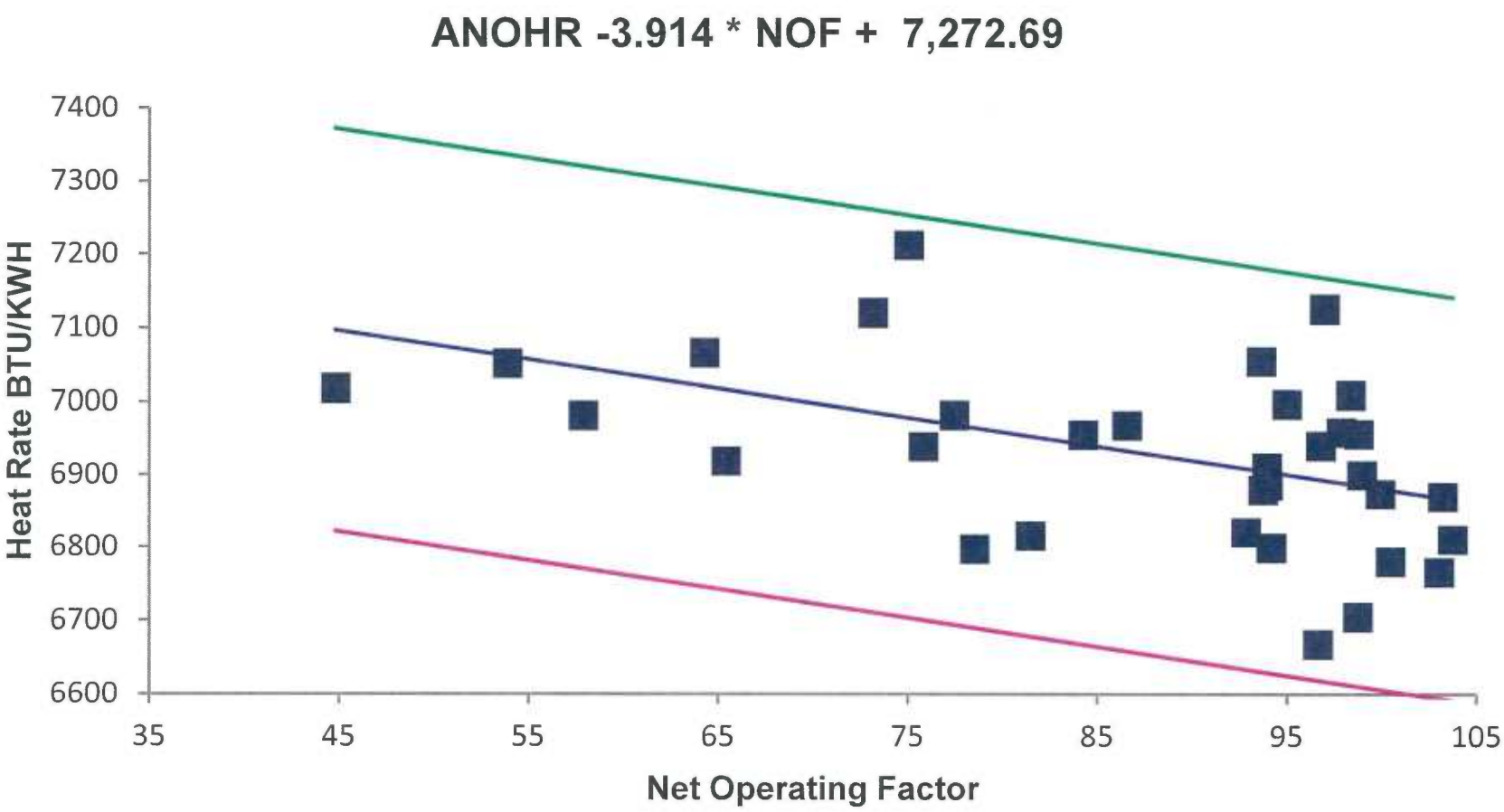
ANOHR -3.914 * NOF + 7,272.69

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-10	93.6	7,055	6,906	148.8	275.1
Aug-10	90.5	7,549	6,919	630.2	275.1
Sep-10	94.0	6,911	6,905	6.1	275.1
Oct-10	92.8	6,821	6,909	-88.4	275.1
Nov-10	103.0	6,766	6,870	-103.3	275.1
Dec-10	103.7	6,811	6,867	-55.7	275.1
Jan-11	84.3	6,956	6,943	12.7	275.1
Feb-11	94.0	6,886	6,905	-19.1	275.1
Mar-11	100.5	6,781	6,880	-98.7	275.1
Apr-11	95.0	6,997	6,901	96.6	275.1
May-11	93.7	6,880	6,906	-26.1	275.1
Jun-11	86.6	6,969	6,934	34.7	275.1
Jul-11	98.4	7,010	6,888	122.2	275.1
Aug-11	97.0	7,126	6,893	232.9	275.1
Sep-11	97.9	6,960	6,890	69.9	275.1
Oct-11	81.5	6,816	6,954	-137.8	275.1
Nov-11	44.8	7,018	7,097	-79.3	275.1
Dec-11	57.9	6,981	7,046	-64.7	275.1
Jan-12	75.8	6,939	6,976	-36.6	275.1
Feb-12	64.3	7,066	7,021	45.3	275.1
Mar-12	103.2	6,870	6,869	1.6	275.1
Apr-12	96.8	6,941	6,894	47.0	275.1
May-12	53.9	7,051	7,062	-10.3	275.1
Jun-12	98.9	6,900	6,885	15.0	275.1
Jul-12	94.2	6,800	6,904	-104.6	275.1
Aug-12	98.8	6,957	6,886	70.8	275.1
Sep-12	99.9	6,874	6,882	-7.5	275.1
Oct-12	98.7	6,705	6,886	-181.3	275.1
Dec-12	77.5	6,982	6,970	12.9	275.1
Jan-13	65.4	6,919	7,017	-97.6	275.1
Feb-13	78.5	6,798	6,965	-167.6	275.1
Mar-13	96.6	6,668	6,895	-226.7	275.1
Apr-13	75.1	7,213	6,979	233.7	275.1
May-13	73.2	7,121	6,986	134.2	275.1
Jun-13	98.0	6,480	6,889	-409.4	275.1

Regression Output:

Constant	7272.69
Std Err of Y Est	169.6868983
R Squared	0.113343864
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-3.913525479
Std Err of Coef.	1.90541597


ANOHR -3.914 * NOF + 7,272.69
Heat Rate BTU/KWH
7400
7300
7200
7100
7000
6900
6800
6700
6600
35
45
55
65
75
85
95
105
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

UNIT UNAVAILABLE OUTAGE RATE SUMMARY

Duke Energy Florida
Period of: January 2014 - December 2014

UNIT	RATE	LOW RANGE	HIGH RANGE	TARGET
Bartow 4	FOR	0.87	3.30	1.65
	MOR	0.41	1.56	0.78
	FOR&MOR	1.27	4.76	2.41
	PFOR	0.49	1.88	0.94
	PMOR	0.11	0.40	0.20
	EUOR	1.86	6.93	3.52
	EUOF	1.86	6.91	3.51
Crystal River 4	FOR	1.26	4.79	2.40
	MOR	1.59	6.06	3.03
	FOR&MOR	2.81	10.27	5.29
	PFOR	0.47	1.79	0.90
	PMOR	0.58	2.20	1.10
	EUOR	3.83	13.89	7.18
	EUOF	3.60	13.06	6.75
Crystal River 5	FOR	1.27	4.85	2.43
	MOR	0.55	2.11	1.06
	FOR&MOR	1.81	6.76	3.43
	PFOR	0.26	1.00	0.50
	PMOR	0.67	2.57	1.28
	EUOR	2.73	10.09	5.15
	EUOF	2.57	9.48	4.84
Hines 1	FOR	0.96	3.66	1.83
	MOR	0.80	3.06	1.53
	FOR&MOR	1.75	6.49	3.30
	PFOR	0.47	1.81	0.90
	PMOR	0.31	1.16	0.58
	EUOR	2.51	9.28	4.74
	EUOF	2.01	7.41	3.78
Hines 2	FOR	0.51	1.95	0.98
	MOR	0.33	1.25	0.63
	FOR&MOR	0.84	3.15	1.59
	PFOR	0.15	0.56	0.28
	PMOR	0.90	3.44	1.72
	EUOR	1.88	7.03	3.56
	EUOF	1.58	5.89	2.98
Hines 3	FOR	0.02	0.08	0.04
	MOR	0.08	0.32	0.16
	FOR&MOR	0.10	0.40	0.20
	PFOR	0.08	0.31	0.16
	PMOR	0.09	0.33	0.16
	EUOR	0.27	1.04	0.52
	EUOF	0.24	0.91	0.46
Hines 4	FOR	0.44	1.68	0.84
	MOR	0.04	0.16	0.08
	FOR&MOR	0.48	1.83	0.92
	PFOR	0.34	1.29	0.64
	PMOR	0.12	0.45	0.23
	EUOR	0.94	3.54	1.78
	EUOF	0.88	3.31	1.67

Bartow
Unit 4

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	744.00	744.00	720.00	744.00	720.00	744.00	620.93	498.78	622.89	684.88	685.71	680.68	663.19	737.76	657.26	680.34	602.38	506.66
RSH	0.00	0.00	0.00	0.00	0.00	0.00	60.08	20.46	64.45	16.02	7.84	2.13	18.71	1.02	20.28	59.62	17.11	97.24
UH	0.00	0.00	0.00	0.00	0.00	0.00	62.99	152.76	55.66	19.10	50.45	37.19	62.10	5.22	42.46	4.04	101.51	140.10
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	152.76	50.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.24	140.10
FOH	0.00	0.00	0.00	0.00	0.00	0.00	62.99	0.00	5.12	18.20	18.51	37.19	62.10	5.07	42.46	4.04	8.27	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.90	31.95	0.00	0.00	0.14	0.00	0.00	0.00	0.00
PFOH	271.87	67.14	2.40	0.00	22.06	100.88	0.00	0.00	0.00	0.00	0.02	90.65	0.00	75.57	13.13	9.84	13.33	0.00
LRPF	410.98	178.66	177.92	0.00	184.09	184.01	0.00	0.00	0.00	0.00	57.00	20.00	0.00	66.30	21.81	74.42	170.23	0.00
EFOH	98.62	10.59	0.38	0.00	3.58	16.38	0.00	0.00	0.00	0.00	0.00	1.60	0.00	4.42	0.25	0.65	2.00	0.00
PMOH	0.00	0.00	10.78	97.58	0.00	0.00	0.00	0.00	0.00	28.68	23.21	30.40	29.64	63.19	47.26	16.83	3.92	0.00
LRPM	0.00	0.00	179.04	178.01	0.00	0.00	0.00	0.00	0.00	81.53	65.61	65.50	65.78	65.64	62.00	55.28	75.61	0.00
EMOH	0.00	0.00	1.70	15.33	0.00	0.00	0.00	0.00	0.00	2.06	1.34	1.76	1.72	3.66	2.59	0.82	0.26	0.00
NPC	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	0.00	0.00	0.00	0.00	0.00	0.00	9.21	0.00	0.82	2.59	2.63	5.18	8.56	0.68	6.07	0.59	1.35	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	4.45	0.00	0.00	0.02	0.00	0.00	0.00	0.00
PFOR	13.25	1.42	0.05	0.00	0.50	2.20	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.60	0.04	0.10	0.33	0.00
PMOR	0.00	0.00	0.24	2.06	0.00	0.00	0.00	0.00	0.00	0.30	0.20	0.26	0.26	0.50	0.39	0.12	0.04	0.00
EUOR	13.25	1.42	0.29	2.06	0.50	2.20	9.21	0.00	0.82	3.01	7.04	5.65	8.80	1.79	6.47	0.80	1.73	0.00
EUOF	13.25	1.42	0.29	2.06	0.50	2.20	8.47	0.00	0.69	2.94	6.96	5.63	8.58	1.79	6.29	0.74	1.46	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.73	6.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.93	16.83
EAF	86.75	98.58	99.71	97.94	99.50	97.80	91.53	77.27	92.51	97.06	93.04	94.37	91.42	98.21	93.71	99.26	85.61	81.17

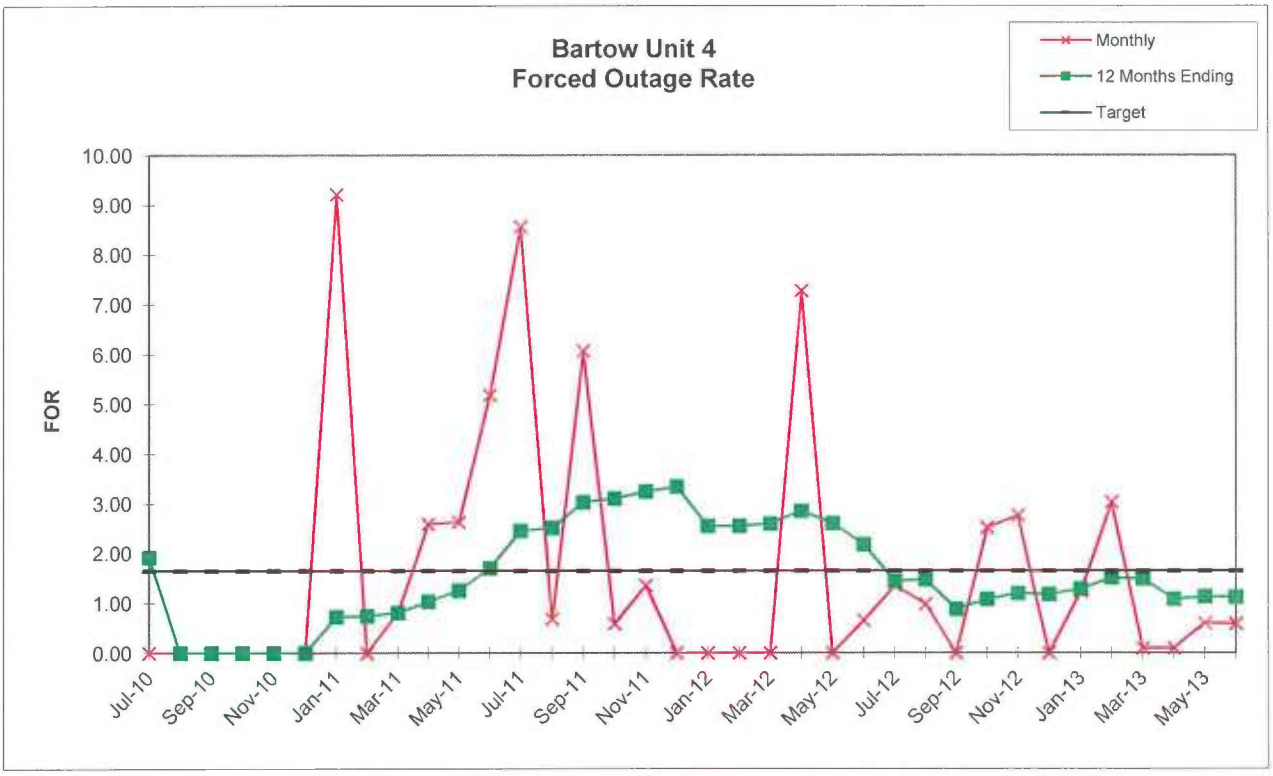
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	1.92	0.00	0.00	0.00	0.00	0.00	0.72	0.74	0.81	1.03	1.25	1.70	2.45	2.51	3.03	3.10	3.24	3.34
MOR	4.31	4.24	4.24	4.24	4.24	4.24	0.00	0.00	0.00	0.01	0.40	0.40	0.40	0.40	0.41	0.41	0.42	0.43
PFOR	7.48	4.94	4.88	4.56	4.21	4.18	3.36	3.24	2.45	2.20	1.82	1.60	0.40	0.32	0.33	0.34	0.32	0.12
PMOR	0.22	0.21	0.23	0.42	0.42	0.42	0.40	0.32	0.33	0.25	0.27	0.27	0.29	0.34	0.35	0.17	0.18	0.19
EUOR	13.30	9.17	9.13	9.00	8.66	8.63	4.46	4.27	3.56	3.46	3.70	3.91	3.51	3.54	4.07	3.98	4.12	4.03
EUOF	13.30	9.17	9.13	9.00	8.66	8.63	4.43	4.16	3.42	3.32	3.54	3.75	3.35	3.38	3.87	3.76	3.84	3.65
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.74	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	3.39	4.98
EAF	86.70	90.83	90.87	91.00	91.34	91.37	95.57	94.10	94.26	94.36	94.14	93.93	94.33	94.30	93.81	93.92	92.77	91.36

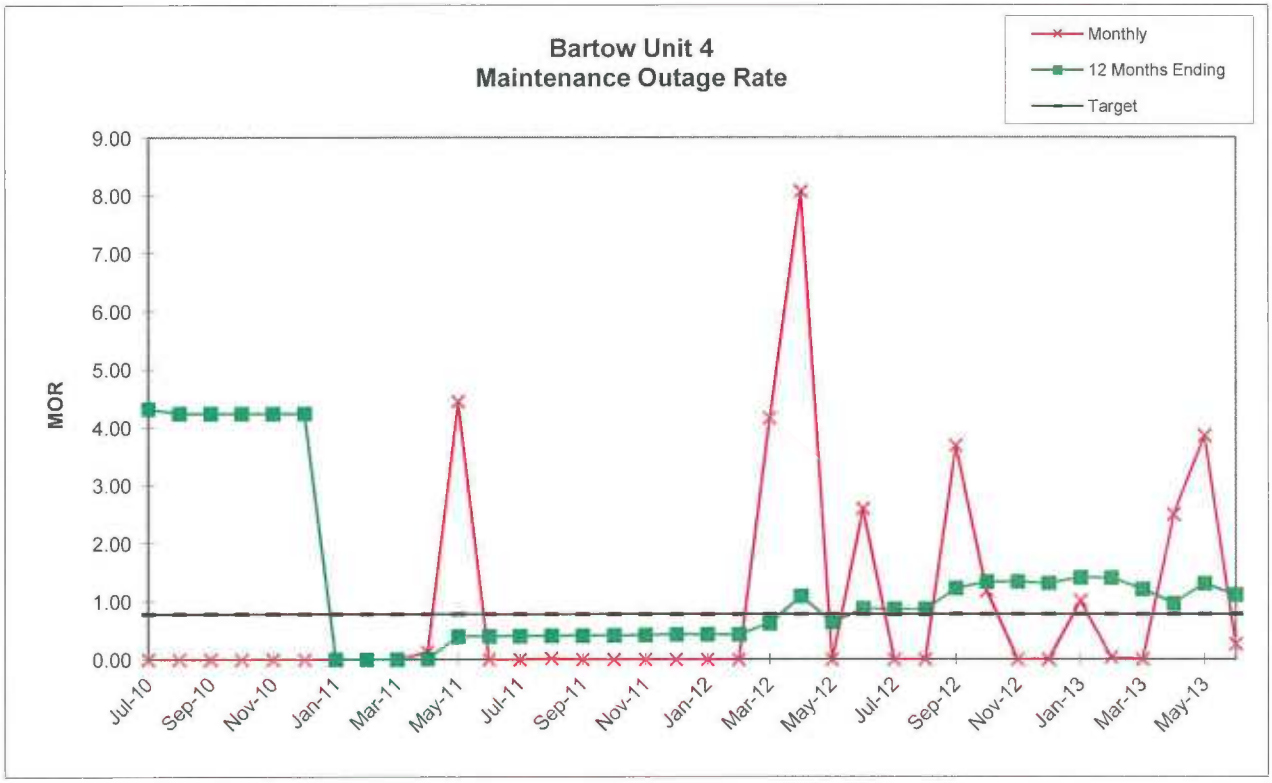
Bartow
Unit 4

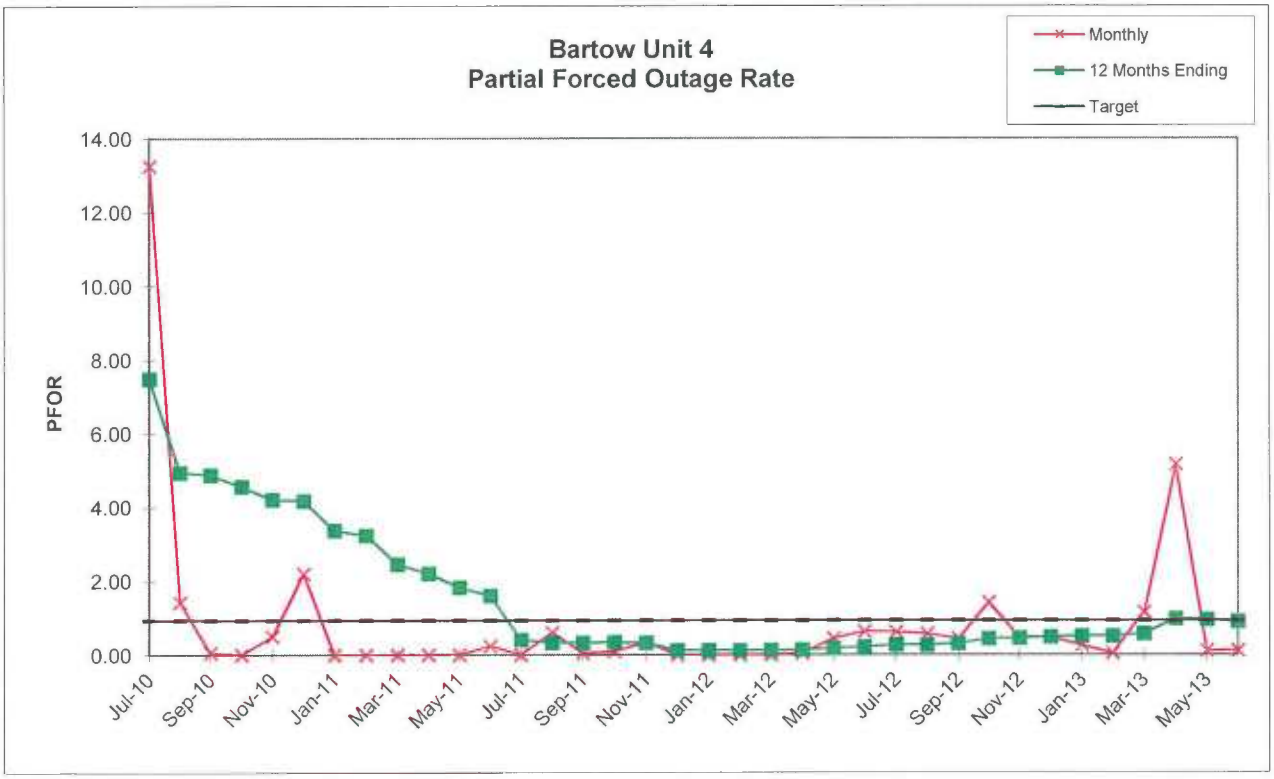
	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	667.06	491.88	296.17	366.02	686.01	607.19	733.95	736.70	679.47	710.45	596.94	634.05	612.51	539.15	406.59	632.49	653.45	690.66
RSH	76.94	71.42	0.74	60.22	8.24	92.64	0.00	0.00	14.51	6.71	5.50	109.95	117.60	28.82	18.64	70.72	60.46	23.47
UH	0.00	132.70	446.09	293.76	49.75	20.17	10.05	7.30	26.02	26.84	118.56	0.00	13.89	104.03	317.77	16.79	30.09	5.87
POH	0.00	132.70	433.23	232.86	49.75	0.00	0.00	0.00	0.00	0.00	101.62	0.00	0.00	86.97	317.39	0.00	0.00	0.00
FOH	0.00	0.00	0.00	28.74	0.00	3.99	10.05	7.30	0.00	18.34	16.94	0.00	7.62	16.85	0.38	0.58	3.89	4.05
MOH	0.00	0.00	12.86	32.15	0.00	16.19	0.00	0.00	26.02	8.50	0.00	0.00	6.27	0.22	0.00	16.21	26.20	1.82
PFOH	0.00	0.00	0.00	50.68	281.71	282.34	314.59	302.40	273.27	413.22	273.00	281.71	8.00	1.65	32.31	223.56	8.86	8.95
LRPF	0.00	0.00	0.00	3.31	12.30	15.41	16.46	15.77	12.35	27.67	11.80	12.21	214.58	156.31	156.49	157.01	90.23	99.51
EFOH	0.00	0.00	0.00	0.15	3.06	3.84	4.57	4.21	2.98	10.09	2.84	3.04	1.60	0.24	4.71	32.68	0.74	0.83
PMOH	5.15	0.00	0.00	37.04	0.00	4.92	21.17	17.06	63.43	9.81	0.00	13.34	0.00	0.00	0.00	0.00	57.82	3.97
LRPM	55.27	0.00	0.00	69.51	0.00	50.58	50.23	39.55	57.20	43.35	0.00	72.92	0.00	0.00	0.00	0.00	101.76	67.53
EMOH	0.25	0.00	0.00	2.27	0.00	0.22	0.94	0.60	3.20	0.38	0.00	0.86	0.00	0.00	0.00	0.00	5.48	0.25
NPC	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1133.00	1074.00	1074.00	1074.00	1074.00	1074.00	1074.00

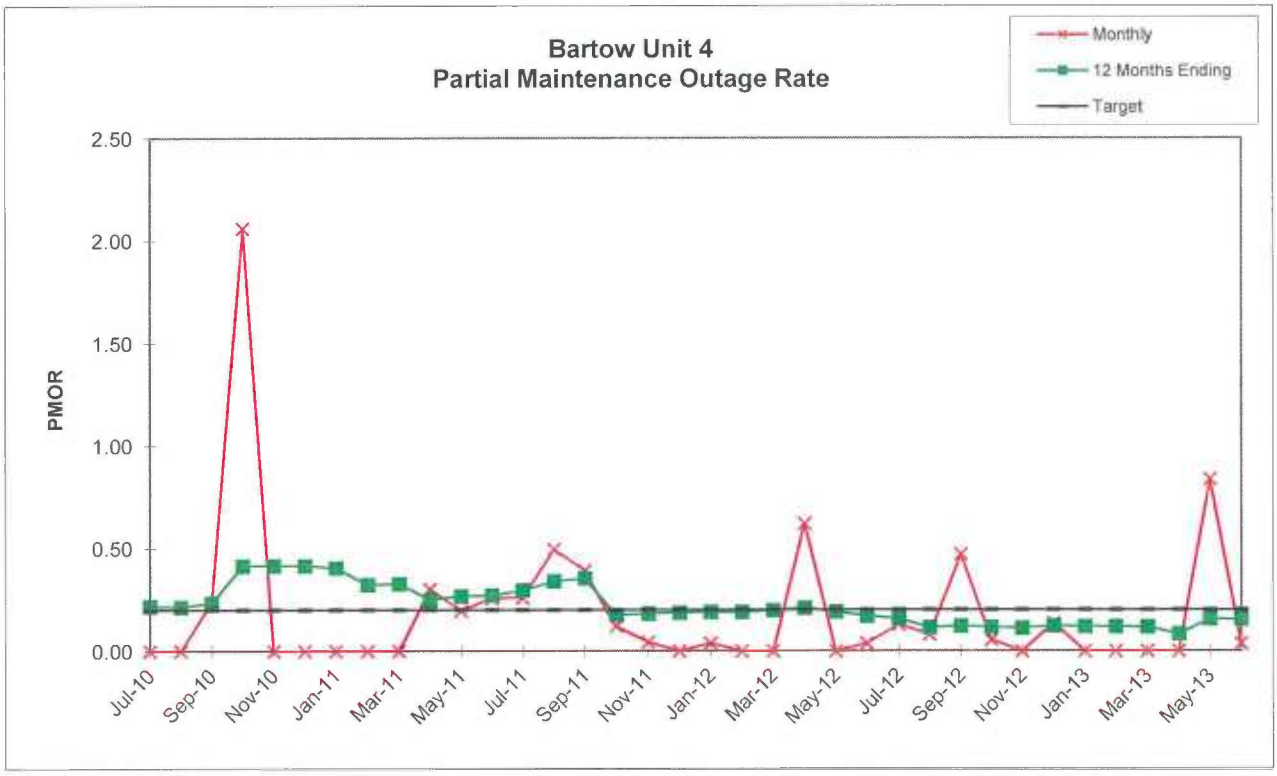
MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.00	0.00	7.28	0.00	0.65	1.35	0.98	0.00	2.52	2.76	0.00	1.23	3.03	0.09	0.09	0.59	0.58
MOR	0.00	0.00	4.16	8.07	0.00	2.60	0.00	0.00	3.69	1.18	0.00	0.00	1.01	0.04	0.00	2.50	3.85	0.26
PFOR	0.00	0.00	0.00	0.04	0.45	0.63	0.62	0.57	0.44	1.42	0.48	0.48	0.26	0.04	1.16	5.17	0.11	0.12
PMOR	0.04	0.00	0.00	0.62	0.00	0.04	0.13	0.08	0.47	0.05	0.00	0.14	0.00	0.00	0.00	0.00	0.84	0.04
EUOR	0.04	0.00	4.16	14.83	0.45	3.86	2.09	1.63	4.56	5.06	3.22	0.61	2.47	3.11	1.25	7.62	5.31	1.00
EUOF	0.03	0.00	1.73	8.79	0.41	3.37	2.09	1.63	4.47	5.01	2.74	0.52	2.08	2.58	0.68	6.87	4.88	0.97
POF	0.00	19.07	58.31	32.34	6.69	0.00	0.00	0.00	0.00	0.00	14.09	0.00	0.00	12.94	42.72	0.00	0.00	0.00
EAF	99.97	80.93	39.96	58.87	92.90	96.63	97.91	98.37	95.53	94.99	83.16	99.48	97.92	84.48	56.60	93.13	95.12	99.03

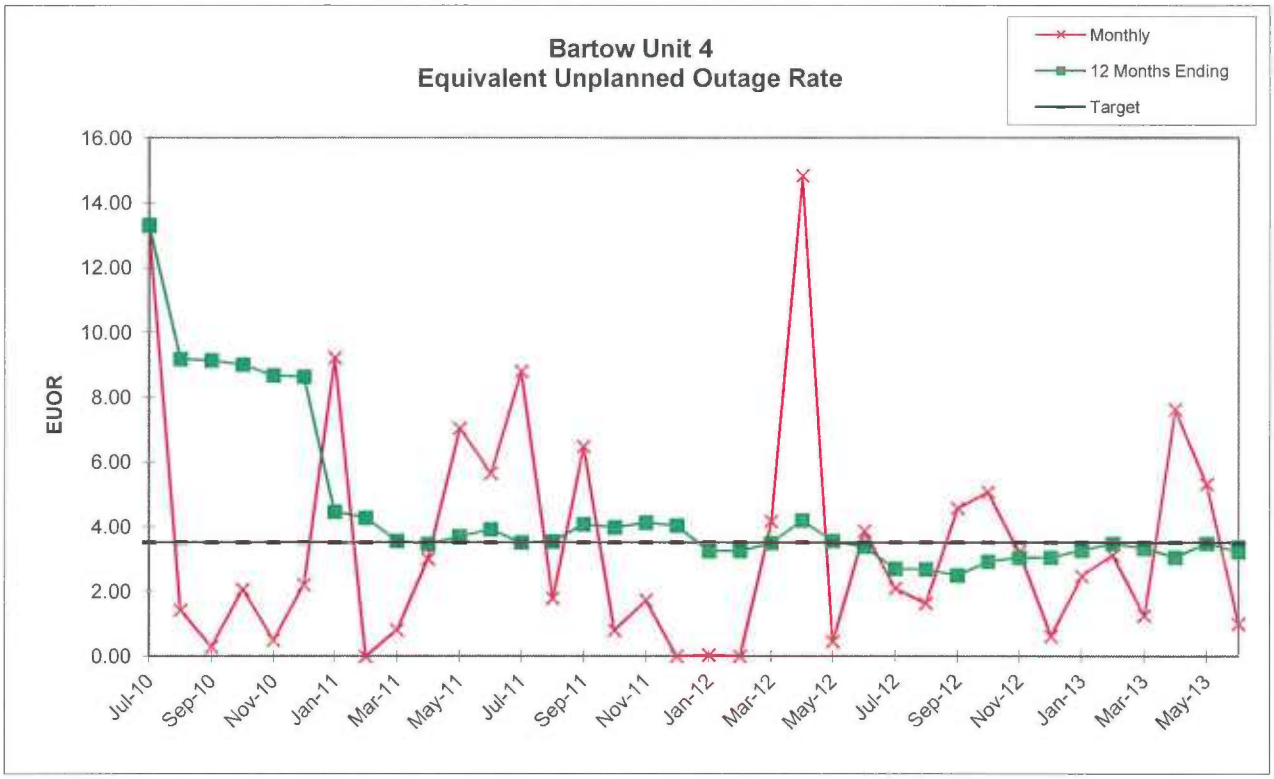
12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	2.55	2.55	2.59	2.85	2.60	2.17	1.44	1.47	0.88	1.07	1.19	1.17	1.28	1.50	1.49	1.07	1.13	1.12
MOR	0.43	0.43	0.62	1.08	0.64	0.87	0.86	0.86	1.22	1.33	1.33	1.31	1.41	1.40	1.21	0.96	1.30	1.11
PFOR	0.12	0.12	0.12	0.13	0.17	0.21	0.27	0.27	0.30	0.44	0.45	0.48	0.51	0.51	0.57	0.97	0.95	0.90
PMOR	0.19	0.19	0.20	0.21	0.19	0.17	0.16	0.11	0.12	0.11	0.11	0.12	0.12	0.12	0.12	0.08	0.15	0.15
EUOR	3.25	3.25	3.49	4.20	3.56	3.37	2.69	2.68	2.49	2.91	3.04	3.04	3.26	3.47	3.32	3.05	3.48	3.22
EUOF	2.94	2.93	3.02	3.50	2.94	2.76	2.21	2.19	2.04	2.41	2.51	2.56	2.73	2.94	2.85	2.69	3.07	2.87
POF	4.98	4.74	9.10	11.75	12.32	12.32	12.32	12.32	12.32	12.32	12.41	10.82	10.82	10.32	9.00	6.34	5.78	5.78
EAF	92.08	92.33	87.88	84.75	84.74	84.93	85.48	85.49	85.64	85.28	85.08	86.63	86.45	86.74	88.15	90.97	91.16	91.35

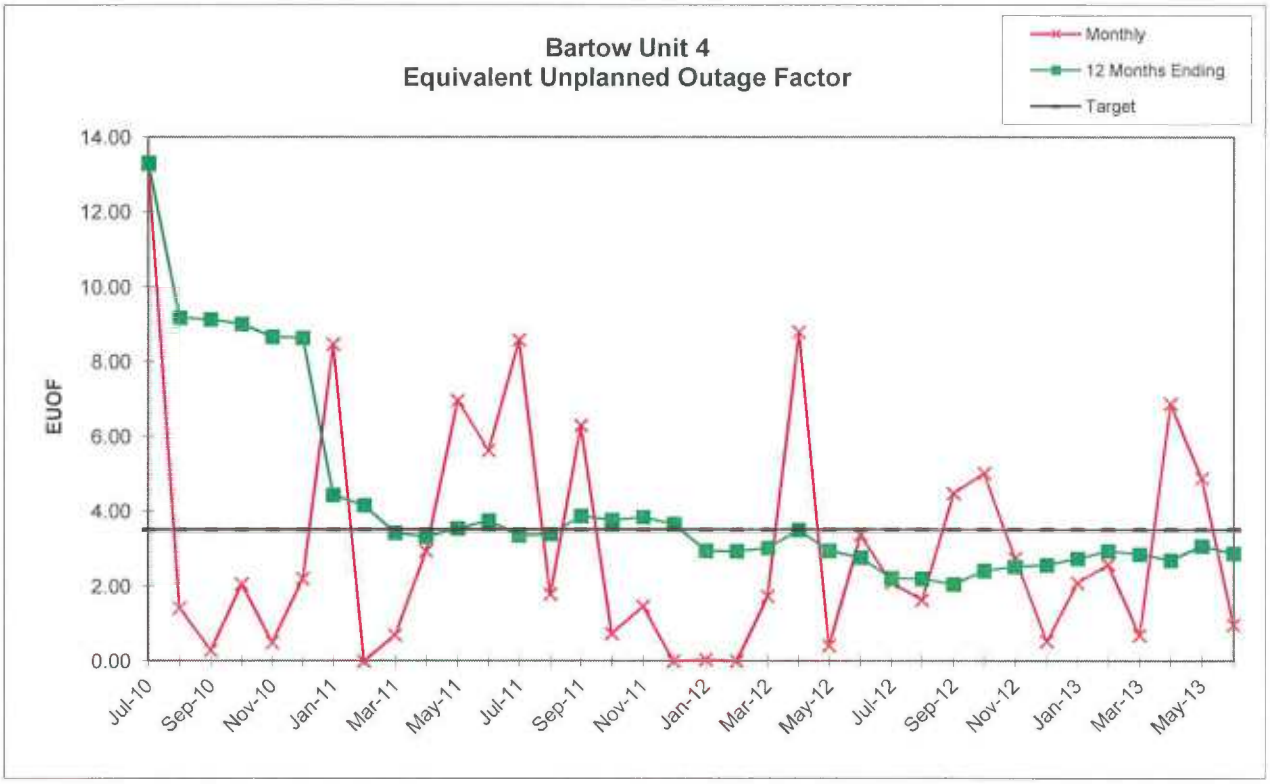

Bartow Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Bartow Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Bartow Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Bartow Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
2.50
2.00
1.50
1.00
0.50
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Bartow Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Bartow Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Crystal River
Unit 4

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	707.82	673.00	437.70	687.78	703.85	727.63	744.00	669.62	743.00	513.72	744.00	655.97	680.27	744.00	720.00	662.85	0.00	300.85
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	36.18	71.00	282.30	56.22	17.15	16.37	0.00	2.38	0.00	206.28	0.00	64.03	63.73	0.00	0.00	81.15	721.00	443.15
POH	0.00	0.00	12.17	0.00	0.00	0.00	0.00	0.00	0.00	202.95	0.00	0.00	0.00	0.00	0.00	81.15	721.00	443.15
FOH	36.18	71.00	270.13	13.97	17.15	16.37	0.00	2.38	0.00	3.33	0.00	8.63	63.73	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	42.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.40	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	160.00	40.72	31.84	7.00	0.00	11.15	0.00	139.22	11.07	0.00	0.00	26.31	36.34	0.00	0.00	0.00	0.00	0.00
LRPF	95.48	87.19	175.99	464.00	0.00	488.00	0.00	102.20	210.96	0.00	0.00	84.19	333.75	0.00	0.00	0.00	0.00	0.00
EFOH	21.76	5.06	7.98	4.63	0.00	7.75	0.00	20.36	3.34	0.00	0.00	3.17	17.35	0.00	0.00	0.00	0.00	0.00
PMOH	13.13	7.98	0.00	86.40	16.00	0.00	43.30	33.00	12.00	21.35	7.00	13.75	25.71	3.98	28.29	12.00	0.00	0.00
LRPM	326.31	83.04	0.00	124.96	84.00	0.00	209.64	445.94	251.00	192.35	100.43	93.82	294.55	80.07	406.73	318.00	0.00	0.00
EMOH	6.10	0.94	0.00	15.38	1.91	0.00	12.99	21.05	4.31	5.87	1.01	1.85	10.83	0.46	16.46	5.46	0.00	0.00
NPC	702.00	702.00	702.00	702.00	702.00	702.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	4.86	9.54	38.16	1.99	2.38	2.20	0.00	0.35	0.00	0.64	0.00	1.30	8.57	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	5.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.79	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	3.07	0.75	1.82	0.67	0.00	1.07	0.00	3.04	0.45	0.00	0.00	0.48	2.55	0.00	0.00	0.00	0.00	0.00
PMOR	0.86	0.14	0.00	2.24	0.27	0.00	1.75	3.14	0.58	1.14	0.14	0.28	1.59	0.06	2.29	0.82	0.00	0.00
EUOR	8.61	10.35	39.29	10.25	2.64	3.24	1.75	6.52	1.03	1.78	0.14	9.59	12.35	0.06	2.29	0.82	0.00	0.00
EUOF	8.61	10.35	38.63	10.25	2.64	3.24	1.75	6.52	1.03	1.28	0.14	9.59	12.35	0.06	2.29	0.73	0.00	0.00
POF	0.00	0.00	1.69	0.00	0.00	0.00	0.00	0.00	0.00	28.19	0.00	0.00	0.00	0.00	0.00	10.91	100.00	59.56
EAF	91.39	89.65	59.68	89.75	97.36	96.76	98.25	93.48	98.97	70.53	99.86	90.41	87.65	99.94	97.71	88.36	0.00	40.44

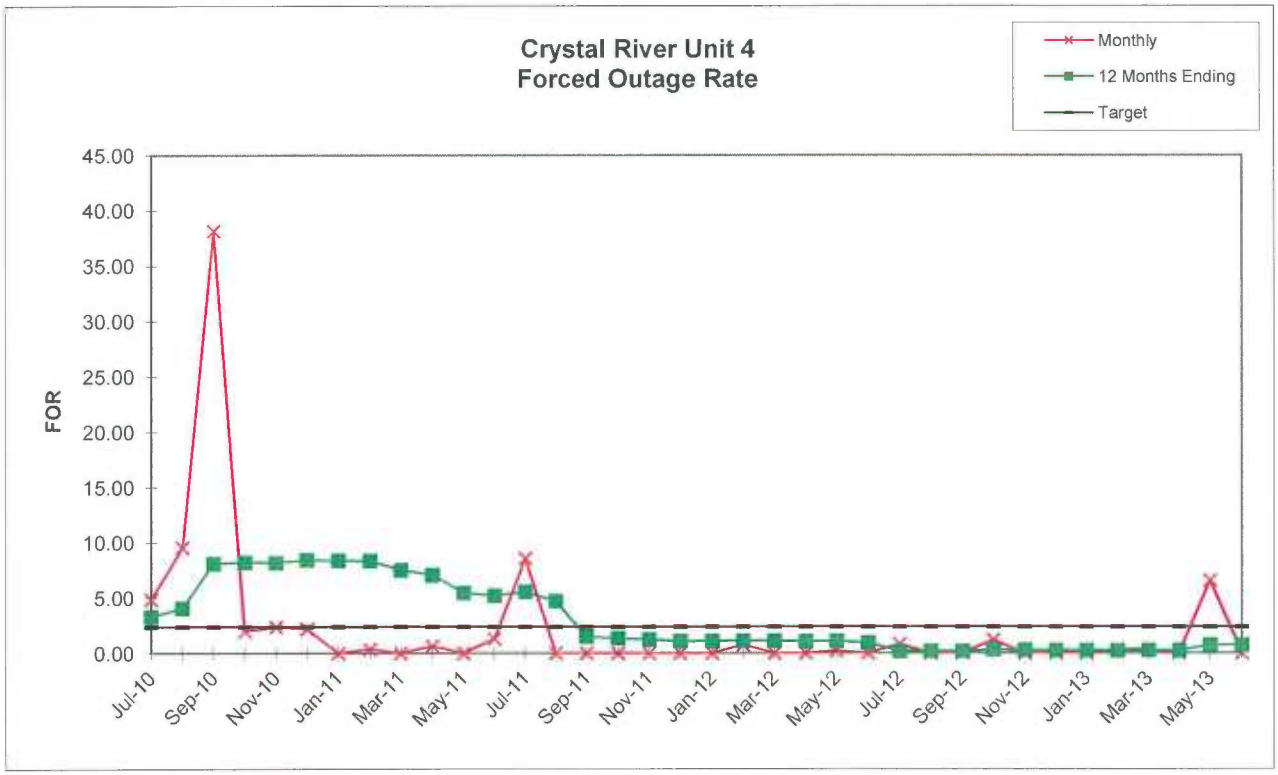
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	3.30	4.06	8.09	8.20	8.17	8.42	8.35	8.33	7.51	7.06	5.43	5.20	5.52	4.68	1.48	1.33	1.23	1.08
MOR	3.02	3.05	3.12	3.80	0.68	0.68	0.68	0.67	0.60	0.56	0.53	1.20	1.21	1.20	1.16	0.66	0.72	0.77
PFOR	2.31	2.15	2.17	2.21	2.11	1.84	1.53	1.14	1.07	0.99	0.92	0.92	0.87	0.80	0.68	0.63	0.68	0.62
PMOR	3.78	3.55	3.30	2.87	2.72	1.31	0.95	1.03	0.98	0.99	0.95	0.89	0.95	0.94	1.11	0.99	1.06	1.12
EUOR	11.85	12.18	15.62	15.91	13.15	11.85	11.18	10.87	9.90	9.38	7.66	7.98	8.31	7.41	4.35	3.55	3.64	3.53
EUOF	9.02	9.27	12.10	12.33	10.19	9.18	8.66	8.48	8.56	8.67	7.37	7.79	8.11	7.23	4.25	3.44	3.22	2.94
POF	22.40	22.40	22.53	22.53	22.53	22.53	22.53	22.00	13.52	7.62	3.74	2.46	2.46	2.46	2.32	3.24	11.47	16.53
EAF	68.58	68.33	65.37	65.14	67.28	68.29	68.81	69.52	77.91	83.71	88.89	89.76	89.44	90.31	93.44	93.32	85.31	80.52

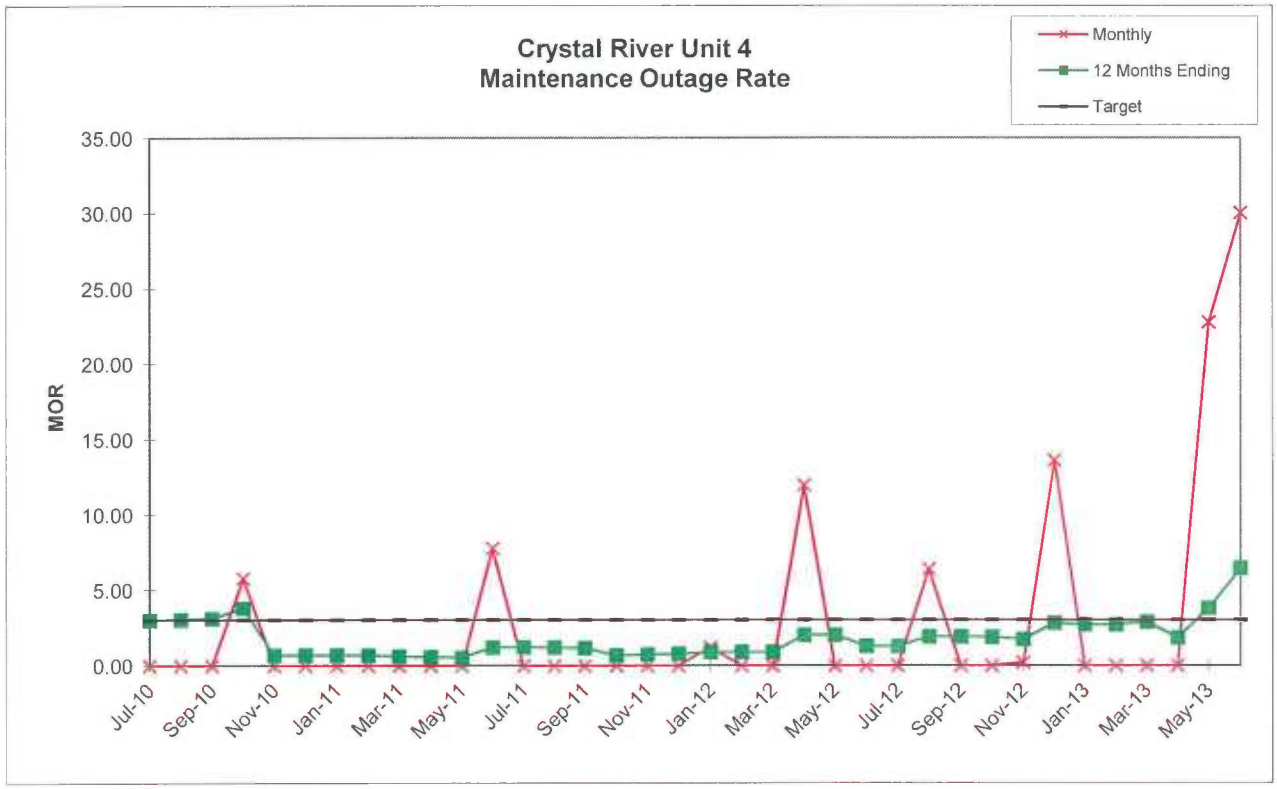
Crystal River
Unit 4

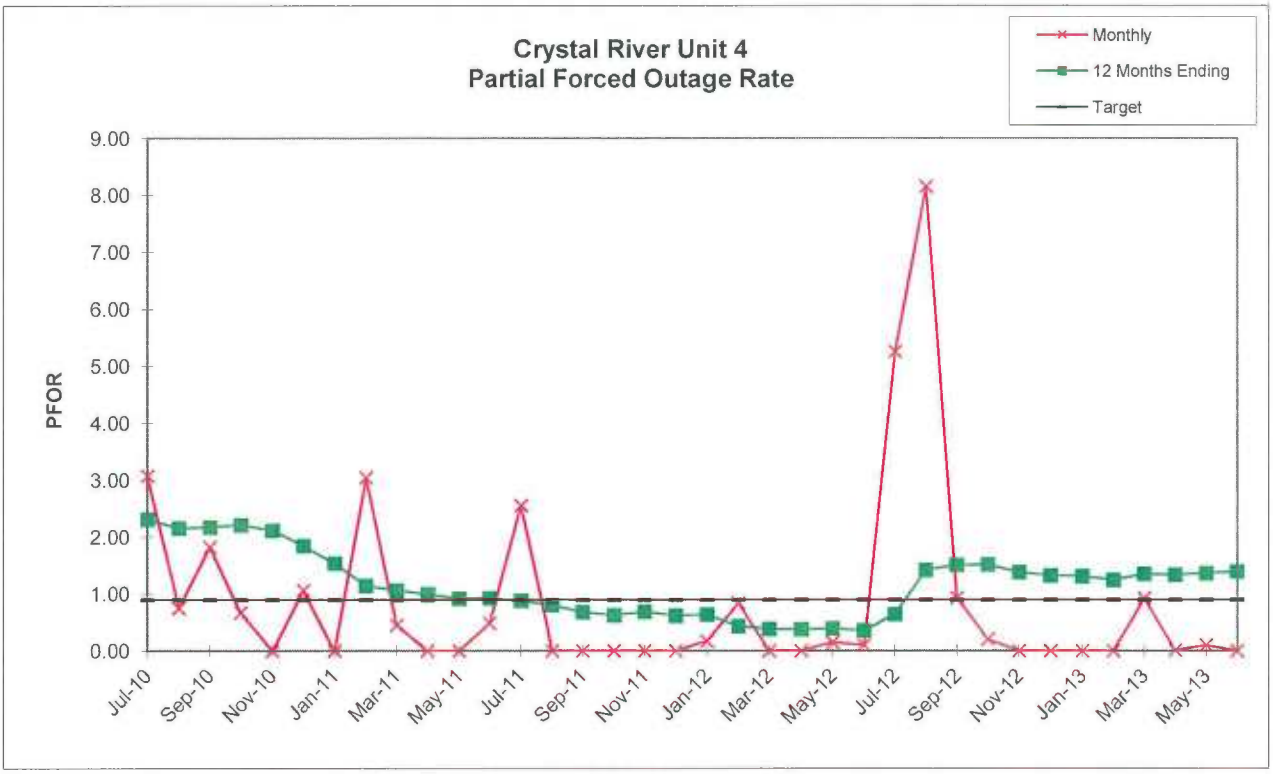
	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	735.00	690.83	743.00	633.70	742.60	720.00	737.88	696.38	720.00	735.23	719.52	642.70	744.00	669.77	225.53	720.00	544.97	503.80
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	9.00	5.17	0.00	86.30	1.40	0.00	6.12	47.62	0.00	8.77	1.48	101.30	0.00	2.23	517.47	0.00	199.04	216.20
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	516.80	0.00	0.00	0.00
FOH	0.00	5.17	0.00	0.00	1.40	0.00	6.12	0.00	0.00	8.77	0.00	0.00	0.00	2.23	0.67	0.00	38.27	0.00
MOH	9.00	0.00	0.00	86.30	0.00	0.00	0.00	47.62	0.00	0.00	1.48	101.30	0.00	0.00	0.00	0.00	160.77	216.20
PFOH	12.00	17.47	0.00	0.00	3.67	10.52	425.00	640.15	118.68	35.73	0.00	0.00	0.00	0.00	16.00	10.75	8.72	0.00
LRPF	74.00	235.95	0.00	0.00	212.90	48.54	65.00	63.14	40.24	29.63	0.00	0.00	0.00	0.00	93.00	4.97	44.17	0.00
EFOH	1.25	5.79	0.00	0.00	1.10	0.72	38.80	56.77	6.71	1.49	0.00	0.00	0.00	0.00	2.09	0.08	0.54	0.00
PMOH	9.00	279.50	23.00	13.75	30.06	26.96	30.75	56.16	46.83	111.46	17.00	4.00	0.00	29.98	0.00	12.50	0.00	0.00
LRPM	52.11	93.00	225.87	303.13	212.31	402.51	267.01	118.80	303.71	99.06	474.00	84.00	0.00	42.78	0.00	241.72	0.00	0.00
EMOH	0.66	36.51	7.30	5.85	8.96	15.24	11.53	9.37	19.98	15.51	11.32	0.47	0.00	1.80	0.00	4.24	0.00	0.00
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00

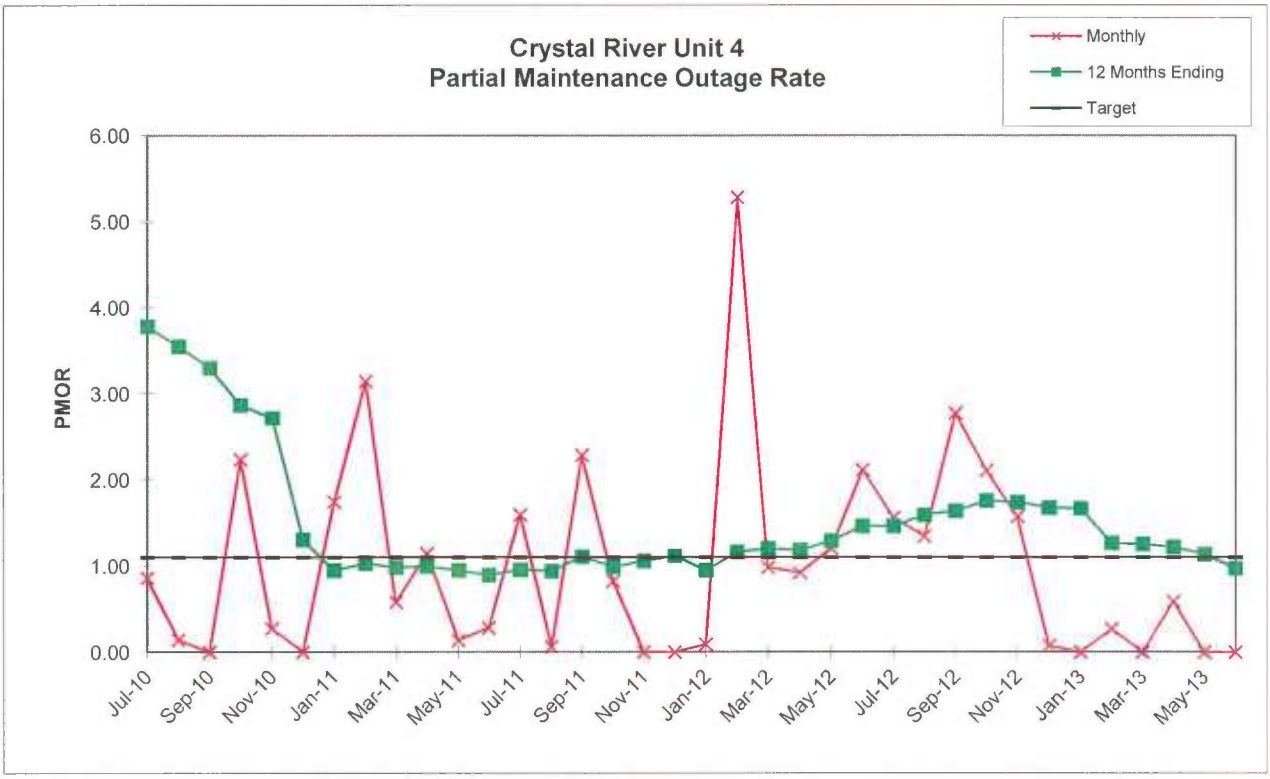
MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.74	0.00	0.00	0.19	0.00	0.82	0.00	0.00	1.18	0.00	0.00	0.00	0.33	0.30	0.00	6.56	0.00
MOR	1.21	0.00	0.00	11.99	0.00	0.00	0.00	6.40	0.00	0.00	0.21	13.62	0.00	0.00	0.00	0.00	22.78	30.03
PFOR	0.17	0.84	0.00	0.00	0.15	0.10	5.26	8.15	0.93	0.20	0.00	0.00	0.00	0.00	0.93	0.01	0.10	0.00
PMOR	0.09	5.28	0.98	0.92	1.21	2.12	1.56	1.35	2.77	2.11	1.57	0.07	0.00	0.27	0.00	0.59	0.00	0.00
EUOR	1.47	6.82	0.98	12.80	1.54	2.22	7.59	15.29	3.71	3.46	1.77	13.68	0.00	0.60	1.22	0.60	26.83	30.03
EUOF	1.47	6.82	0.98	12.80	1.54	2.22	7.59	15.29	3.71	3.46	1.77	13.68	0.00	0.60	0.37	0.60	26.83	30.03
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.56	0.00	0.00	0.00
EAF	98.53	93.18	99.02	87.20	98.46	97.78	92.41	84.71	96.29	96.54	98.23	86.32	100.00	99.40	30.07	99.40	73.17	69.97

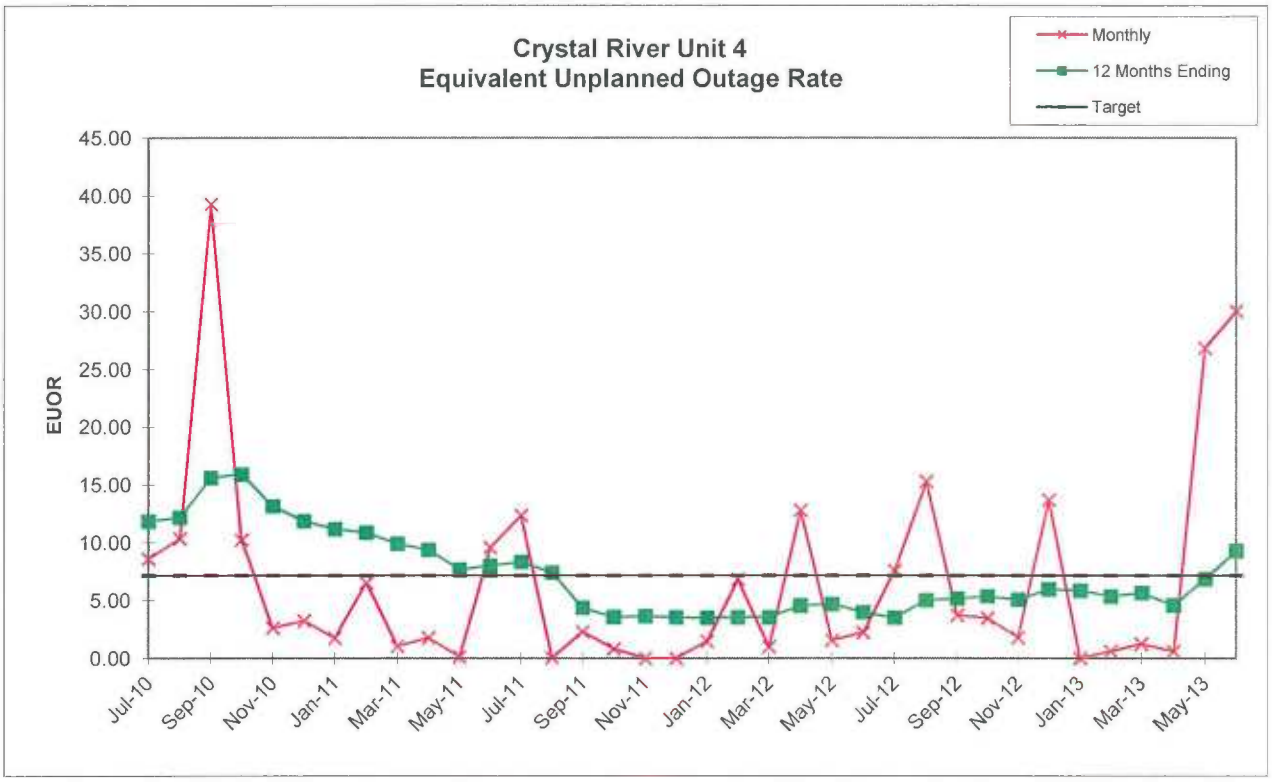
12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	1.08	1.11	1.11	1.05	1.07	0.94	0.17	0.17	0.17	0.29	0.26	0.25	0.25	0.22	0.24	0.24	0.71	0.73
MOR	0.89	0.89	0.89	2.02	2.02	1.28	1.27	1.90	1.90	1.88	1.74	2.80	2.70	2.71	2.88	1.83	3.80	6.44
PFOR	0.63	0.43	0.38	0.38	0.39	0.36	0.64	1.41	1.51	1.51	1.38	1.32	1.31	1.24	1.35	1.33	1.36	1.39
PMOR	0.95	1.16	1.20	1.18	1.29	1.46	1.46	1.59	1.64	1.76	1.74	1.68	1.67	1.26	1.25	1.22	1.14	0.97
EUOR	3.50	3.54	3.53	4.54	4.68	3.97	3.50	5.01	5.14	5.35	5.04	5.95	5.82	5.34	5.62	4.56	6.84	9.27
EUOF	2.92	2.96	2.95	3.90	4.01	3.41	3.01	4.30	4.41	4.64	4.79	5.95	5.82	5.34	5.29	4.29	6.44	8.72
POF	16.53	16.49	16.49	14.18	14.18	14.18	14.18	14.18	14.18	13.25	5.04	0.00	0.00	0.00	5.90	5.90	5.90	5.90
EAF	80.55	80.56	80.56	81.93	81.81	82.41	82.82	81.53	81.41	82.10	90.17	94.05	94.18	94.66	88.81	89.81	87.66	85.38

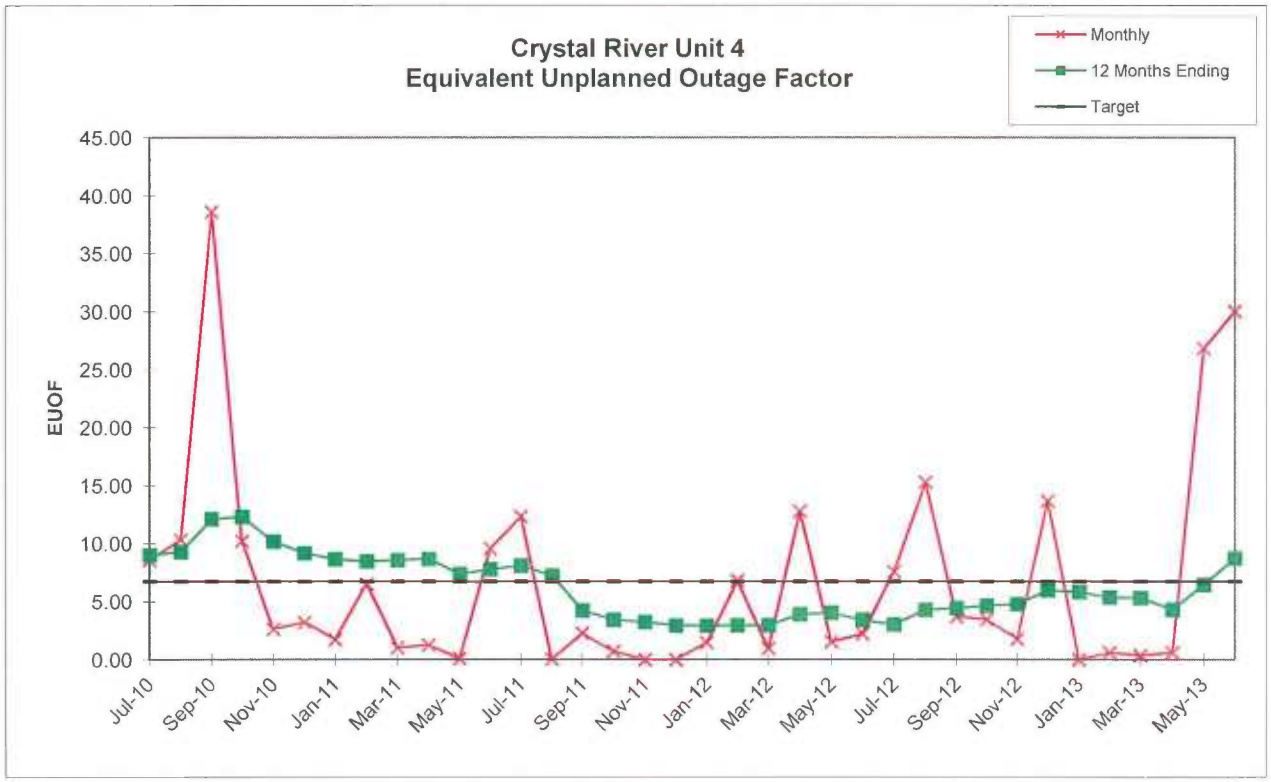

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Crystal River
Unit 5

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	744.00	744.00	648.72	744.00	531.83	744.00	690.85	669.43	743.00	538.70	236.67	678.94	737.62	706.82	720.00	701.28	721.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	71.28	0.00	189.17	0.00	53.15	2.57	0.00	181.30	507.33	41.06	6.38	37.18	0.00	42.72	0.00	0.00
POH	0.00	0.00	0.00	0.00	189.17	0.00	0.00	0.00	0.00	179.20	507.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	71.28	0.00	0.00	0.00	0.00	2.57	0.00	2.10	0.00	5.03	6.38	37.18	0.00	5.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	53.15	0.00	0.00	0.00	0.00	36.03	0.00	0.00	0.00	37.72	0.00	0.00
PFOH	61.77	2.25	29.55	1.00	0.00	0.00	0.00	34.00	0.00	0.00	0.00	17.76	30.45	18.33	1.50	0.00	8.60	0.00
LRPF	78.43	115.00	100.54	82.00	0.00	0.00	0.00	63.09	0.00	0.00	0.00	110.96	119.14	80.01	99.00	0.00	283.79	0.00
EFOH	6.92	0.37	4.24	0.12	0.00	0.00	0.00	3.07	0.00	0.00	0.00	2.82	5.19	2.10	0.21	0.00	3.49	0.00
PMOH	16.58	3.28	0.00	59.14	0.00	187.50	100.42	29.75	96.43	57.75	21.07	71.24	31.00	21.70	54.77	86.32	39.00	18.50
LRPM	266.54	81.08	0.00	99.59	0.00	81.00	130.16	429.81	127.08	273.34	169.62	27.61	54.45	327.45	233.36	89.46	413.46	227.54
EMOH	6.31	0.38	0.00	8.41	0.00	21.70	18.70	18.29	17.53	22.58	5.11	2.81	2.41	10.17	18.28	11.05	23.07	6.02
NPC	700.00	700.00	700.00	700.00	700.00	700.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00	699.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	0.00	0.00	9.90	0.00	0.00	0.00	0.00	0.38	0.00	0.39	0.00	0.74	0.86	5.00	0.00	0.71	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	7.14	0.00	0.00	0.00	0.00	5.04	0.00	0.00	0.00	5.10	0.00	0.00
PFOR	0.93	0.05	0.65	0.02	0.00	0.00	0.00	0.46	0.00	0.00	0.00	0.42	0.70	0.30	0.03	0.00	0.48	0.00
PMOR	0.85	0.05	0.00	1.13	0.00	2.92	2.71	2.73	2.36	4.19	2.16	0.41	0.33	1.44	2.54	1.58	3.20	0.81
EUOR	1.78	0.10	10.49	1.15	0.00	2.92	9.66	3.56	2.36	4.56	2.16	6.49	1.88	6.65	2.57	7.23	3.68	0.81
EUOF	1.78	0.10	10.49	1.15	0.00	2.92	9.66	3.56	2.36	3.43	0.69	6.49	1.88	6.65	2.57	7.23	3.68	0.81
POF	0.00	0.00	0.00	0.00	26.24	0.00	0.00	0.00	0.00	24.89	68.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.22	99.90	89.51	98.85	73.76	97.08	90.34	96.44	97.64	71.68	31.12	93.51	98.12	93.35	97.43	92.77	96.32	99.19

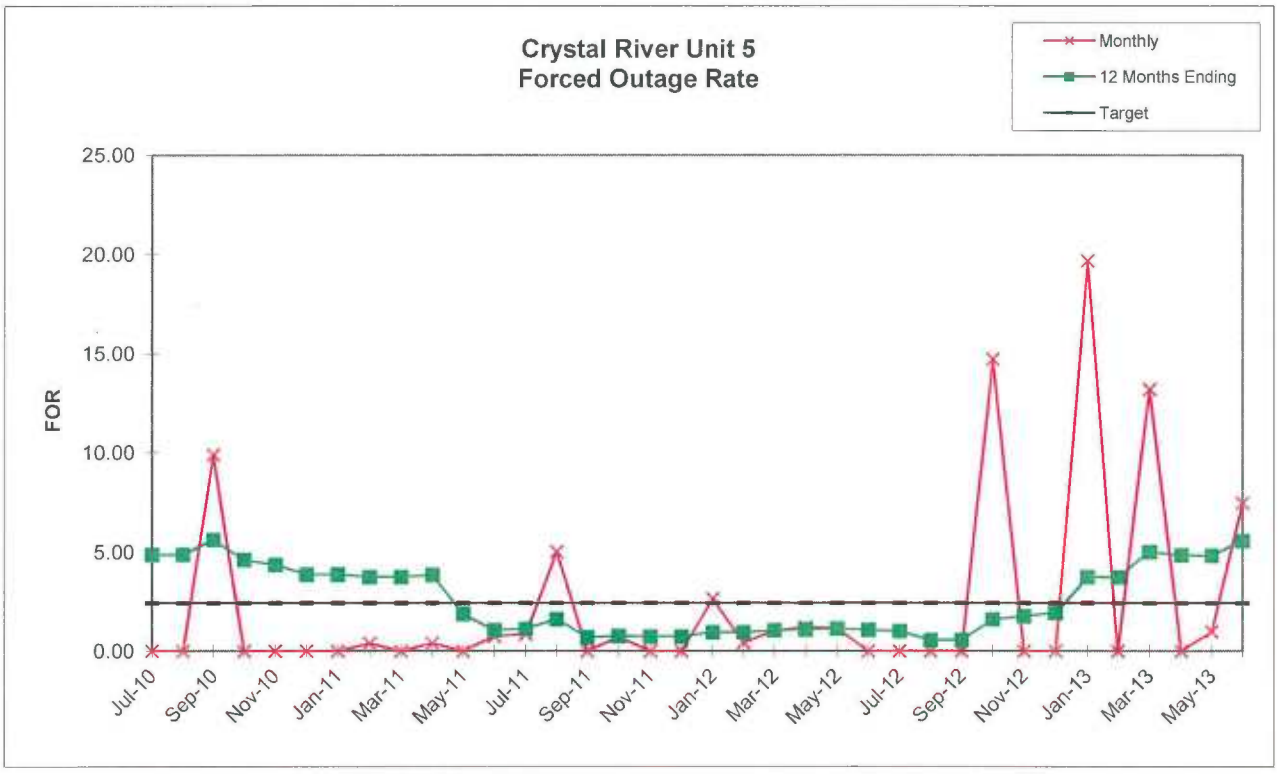
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	4.85	4.85	5.61	4.59	4.34	3.85	3.85	3.73	3.72	3.83	1.86	1.04	1.12	1.60	0.68	0.75	0.73	0.73
MOR	0.84	0.84	0.85	0.84	0.79	0.78	0.79	0.79	0.64	0.66	0.69	1.14	1.14	1.15	1.14	1.62	1.58	1.58
PFOR	1.08	1.08	1.14	1.07	1.01	0.92	0.73	0.63	0.24	0.23	0.22	0.23	0.21	0.23	0.17	0.17	0.21	0.21
PMOR	1.54	1.41	1.31	1.39	1.30	1.54	1.68	1.86	1.89	1.65	1.62	1.58	1.53	1.67	1.89	1.93	2.18	1.98
EUOR	8.09	7.96	8.65	7.67	7.26	6.91	6.87	6.84	6.36	6.24	4.30	3.93	3.94	4.55	3.83	4.40	4.63	4.44
EUOF	7.47	7.35	7.99	7.09	7.08	6.77	6.72	6.69	6.22	5.98	3.87	3.53	3.54	4.10	3.45	3.96	4.27	4.09
POF	7.63	7.63	7.63	7.63	2.50	2.16	2.16	2.16	2.16	4.21	10.00	10.00	10.00	10.00	10.00	10.00	7.84	7.84
EAF	84.90	85.02	84.38	85.29	90.41	91.07	91.12	91.15	91.62	89.82	86.13	86.47	86.46	85.91	86.56	86.04	87.90	88.08

Crystal River
Unit 5

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	542.45	693.00	735.43	632.17	735.57	720.00	744.00	744.00	720.00	533.12	0.00	16.33	597.60	635.00	645.00	720.00	736.78	666.30
RSH	186.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	14.65	3.00	7.57	87.83	8.43	0.00	0.00	0.00	0.00	210.88	721.00	727.67	146.40	37.00	98.00	0.00	7.22	53.70
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	118.88	721.00	727.67	0.00	0.00	0.00	0.00	0.00	0.00
FOH	14.65	3.00	7.57	7.68	8.43	0.00	0.00	0.00	0.00	92.00	0.00	0.00	146.40	0.00	98.00	0.00	7.22	53.70
MOH	0.00	0.00	0.00	80.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.00	0.00	0.00	0.00	0.00
PFOH	1.25	1.58	0.00	12.75	9.50	45.59	30.50	2.08	6.63	4.00	0.00	0.00	48.07	49.90	0.60	19.35	5.50	4.50
LRPF	329.00	706.49	0.00	329.00	567.00	97.37	98.70	171.48	72.04	91.00	0.00	0.00	523.86	286.44	79.00	45.72	28.82	91.00
EFOH	0.58	1.57	0.00	5.91	7.59	6.25	4.24	0.50	0.67	0.51	0.00	0.00	35.47	20.13	0.07	1.25	0.22	0.58
PMOH	76.75	17.33	43.30	154.70	35.06	19.57	15.98	70.37	18.58	10.00	0.00	0.00	0.00	43.29	2.00	5.50	0.00	8.00
LRPM	140.62	125.75	112.05	152.62	92.98	312.13	91.02	91.00	209.45	58.00	0.00	0.00	0.00	155.06	234.00	91.00	0.00	91.00
EMOH	15.20	3.07	6.83	33.25	4.59	8.60	2.05	9.02	5.48	0.82	0.00	0.00	0.00	9.45	0.66	0.70	0.00	1.03
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00

MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	2.63	0.43	1.02	1.20	1.13	0.00	0.00	0.00	0.00	14.72	0.00	0.00	19.68	0.00	13.19	0.00	0.97	7.46
MOR	0.00	0.00	0.00	11.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.51	0.00	0.00	0.00	0.00
PFOR	0.11	0.23	0.00	0.93	1.03	0.87	0.57	0.07	0.09	0.10	0.00	0.00	5.93	3.17	0.01	0.17	0.03	0.09
PMOR	2.80	0.44	0.93	5.26	0.62	1.19	0.28	1.21	0.76	0.15	0.00	0.00	0.00	1.49	0.10	0.10	0.00	0.15
EUOR	5.46	1.10	1.94	17.64	2.77	2.06	0.85	1.28	0.85	14.93	0.00	0.00	24.44	9.91	13.29	0.27	1.00	7.68
EUOF	4.09	1.10	1.94	17.64	2.77	2.06	0.85	1.28	0.85	12.54	0.00	0.00	24.44	9.91	13.29	0.27	1.00	7.68
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.98	100.00	97.81	0.00	0.00	0.00	0.00	0.00	0.00
EAF	95.91	98.90	98.06	82.36	97.23	97.94	99.15	98.72	99.15	71.48	0.00	2.19	75.56	90.09	86.71	99.73	99.00	92.32

12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.93	0.94	1.03	1.09	1.12	1.06	0.98	0.55	0.55	1.59	1.74	1.92	3.71	3.70	4.98	4.82	4.80	5.55
MOR	0.94	0.94	0.94	1.92	1.81	1.39	1.38	1.38	1.38	0.96	1.05	1.16	1.15	1.69	1.71	0.54	0.54	0.54
PFOR	0.23	0.21	0.21	0.28	0.35	0.39	0.38	0.36	0.37	0.38	0.37	0.41	0.91	1.19	1.21	1.13	1.02	0.94
PMOR	1.97	1.77	1.63	1.75	1.64	1.70	1.69	1.67	1.52	1.43	1.26	1.30	1.07	1.18	1.10	0.61	0.54	0.43
EUOR	4.02	3.80	3.76	4.94	4.83	4.46	4.37	3.90	3.76	4.28	4.33	4.70	6.67	7.52	8.69	6.95	6.77	7.33
EUOF	3.61	3.42	3.38	4.55	4.72	4.36	4.27	3.82	3.68	4.13	3.83	3.76	5.48	6.17	7.13	5.71	5.56	6.02
POF	7.84	7.82	7.82	5.78	0.00	0.00	0.00	0.00	0.00	1.35	9.56	17.85	17.85	17.89	17.89	17.89	17.89	17.89
EAF	88.55	88.76	88.80	89.68	95.28	95.64	95.73	96.18	96.32	94.52	86.61	78.40	76.67	75.93	74.97	76.40	76.55	76.09


Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
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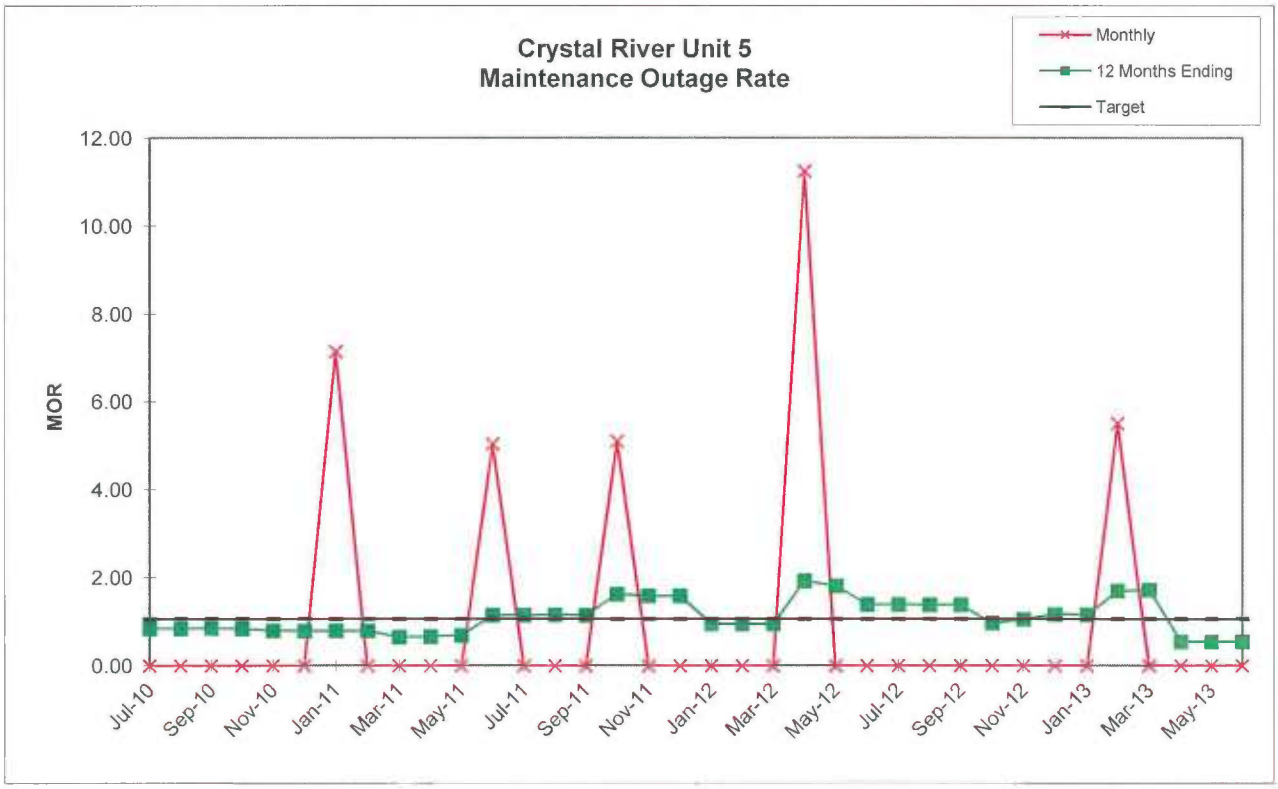
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
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Nov-11
Jan-12
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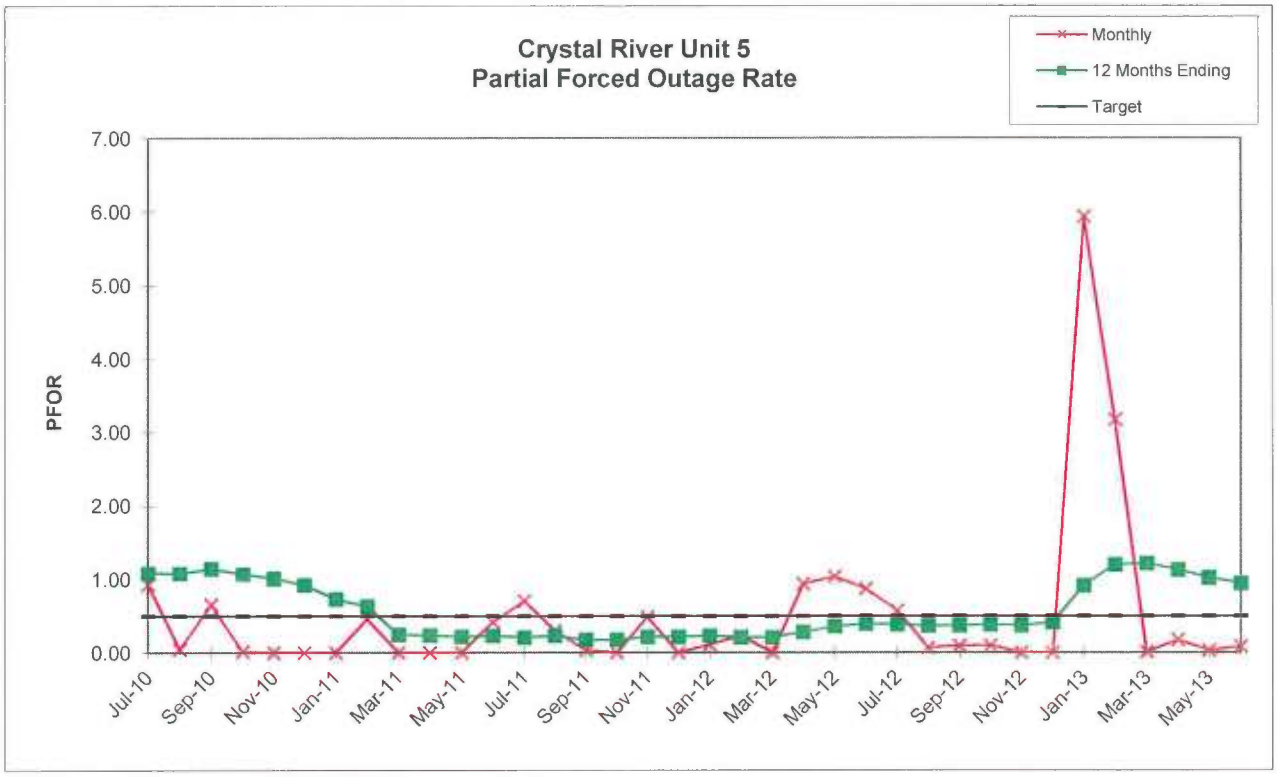
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
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Sep-12
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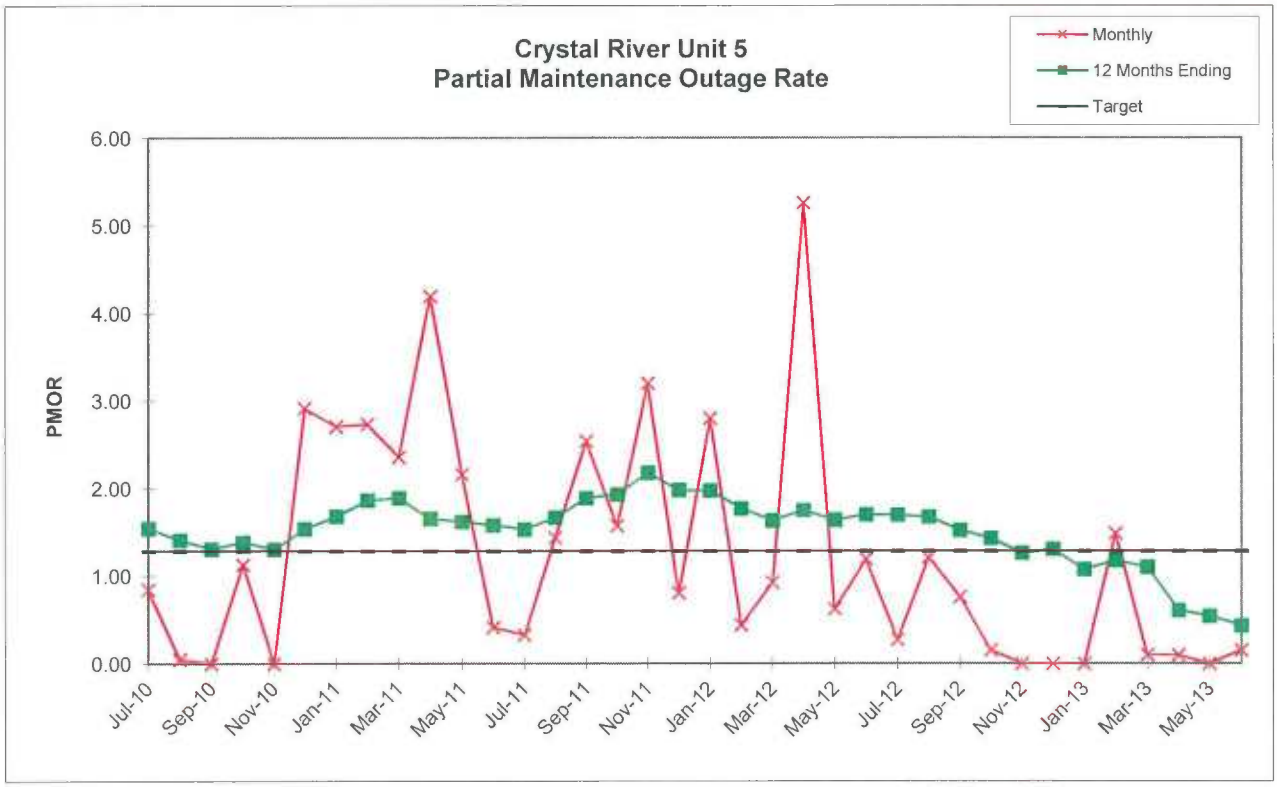
Jan-13
Mar-13
May-13


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
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Jul-12
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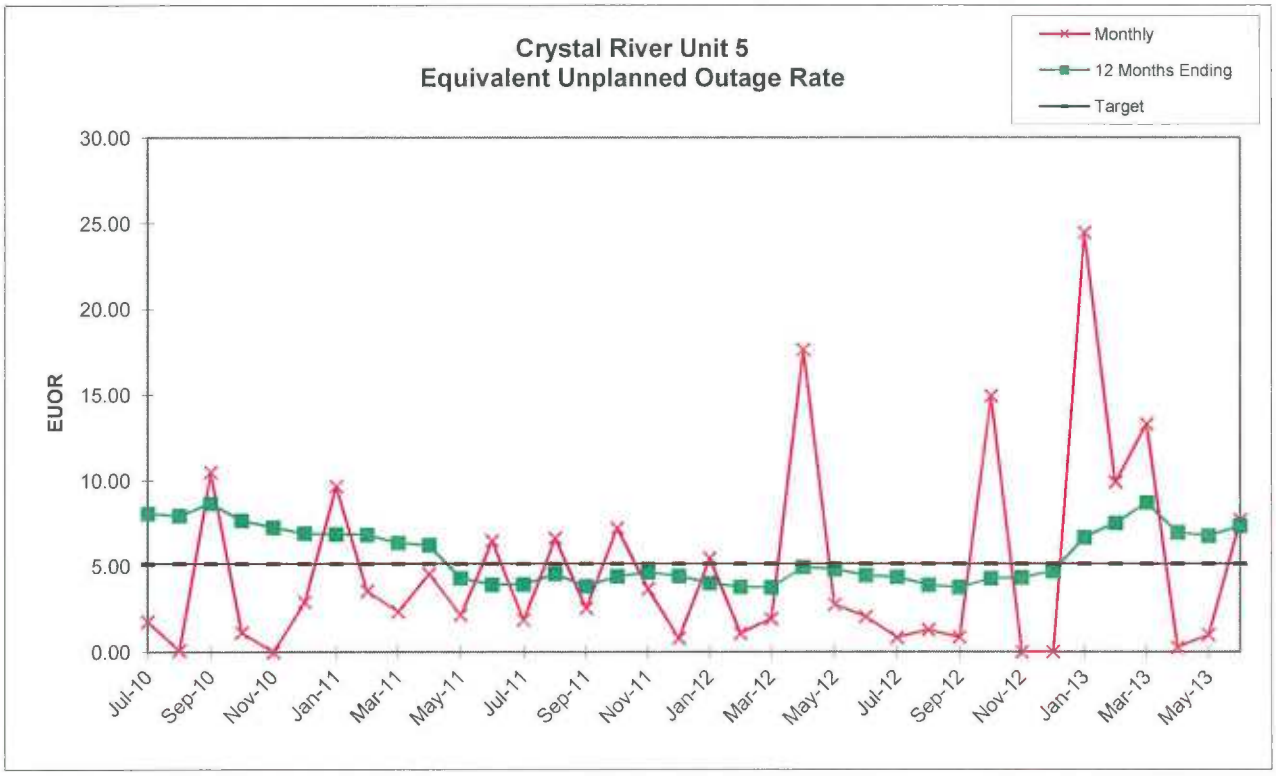
Jan-13
Mar-13
May-13


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
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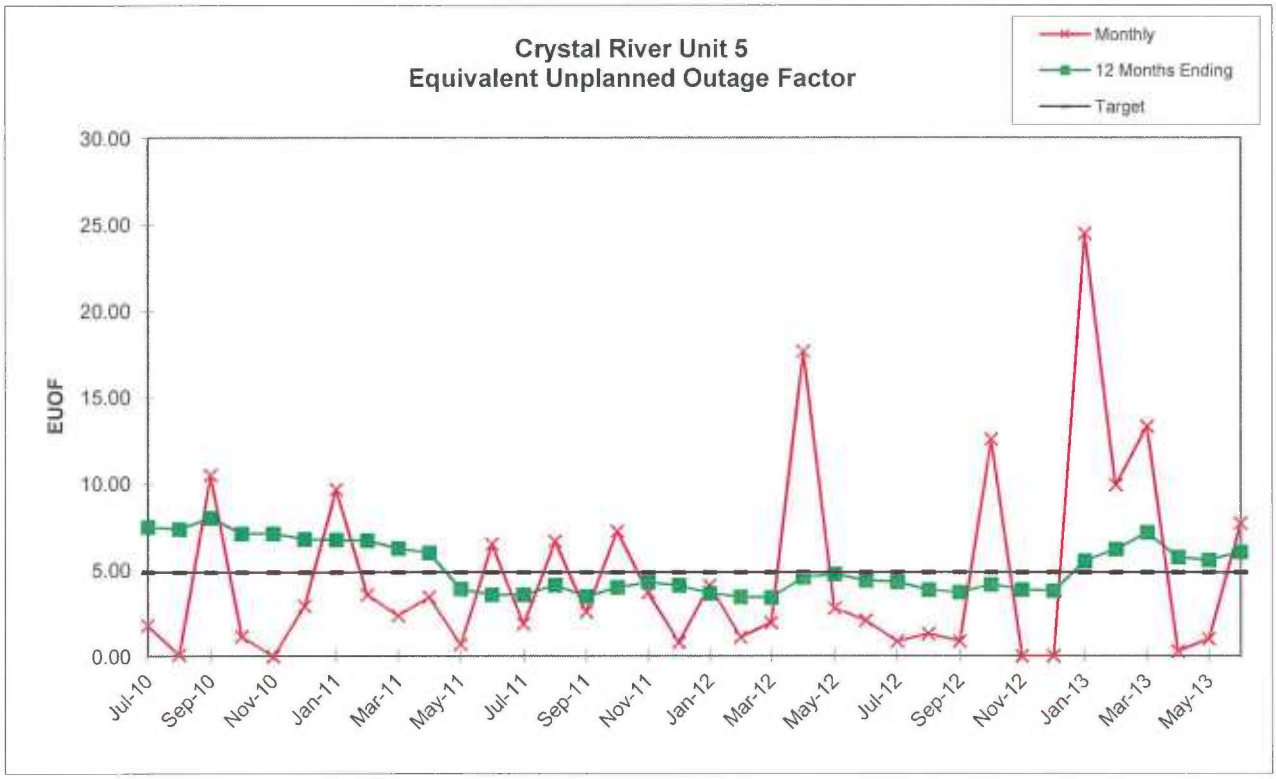
Nov-12
Jan-13
Mar-13
May-13


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Hines
Unit 1

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	744.00	546.37	720.00	526.58	540.75	739.70	685.40	621.02	600.92	0.00	62.33	712.83	744.00	744.00	720.00	744.00	277.22	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.50	0.00
UH	0.00	197.63	0.00	217.42	180.25	4.30	58.60	50.98	142.08	720.00	681.67	7.17	0.00	0.00	0.00	0.00	396.28	0.00
POH	0.00	0.00	0.00	217.42	162.13	0.00	0.00	0.00	142.08	720.00	596.37	0.00	0.00	0.00	0.00	0.00	395.75	0.00
FOH	0.00	197.63	0.00	0.00	18.12	4.30	0.00	15.43	0.00	0.00	85.30	7.17	0.00	0.00	0.00	0.00	0.53	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	58.60	35.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	79.29	3.57	0.00	8.18	20.30	2.83	0.00	5.22	61.24	0.00	291.00	68.17	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	221.98	181.83	0.00	282.11	202.00	202.24	0.00	190.39	193.35	0.00	64.82	177.82	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	38.10	1.41	0.00	5.00	8.88	1.24	0.00	2.15	25.63	0.00	40.83	26.24	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	153.20	0.00	0.00	0.00	0.00	5.00	0.00	3.17	5.61	1.05	1.17	1.57	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	212.00	0.00	0.00	0.00	0.00	132.00	0.00	197.79	191.93	208.00	207.41	197.58	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	70.30	0.00	0.00	0.00	0.00	1.43	0.00	1.36	2.33	0.47	0.53	0.67	0.00
NPC	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	0.00	26.56	0.00	0.00	3.24	0.58	0.00	2.42	0.00	0.00	57.78	1.00	0.00	0.00	0.00	0.00	0.19	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	7.88	5.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	7.23	0.26	0.00	0.73	1.43	0.21	0.00	3.45	3.60	0.00	5.49	3.64	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	9.50	0.00	0.00	0.00	0.00	2.29	0.00	0.18	0.31	0.07	0.07	0.24	0.00
EUOR	0.00	26.56	0.00	7.23	3.49	10.03	8.55	8.91	0.21	0.00	60.20	4.56	0.18	5.80	3.71	0.07	0.43	0.00
EUOF	0.00	26.56	0.00	5.12	2.71	10.03	8.55	8.91	0.17	0.00	11.95	4.56	0.18	5.80	3.71	0.07	0.17	0.00
POF	0.00	0.00	0.00	29.22	22.49	0.00	0.00	0.00	19.12	100.00	80.16	0.00	0.00	0.00	0.00	0.00	54.89	0.00
EAF	100.00	73.44	100.00	65.66	74.81	89.97	91.45	91.09	80.71	0.00	7.90	95.44	99.82	94.20	96.29	99.93	44.94	100.00

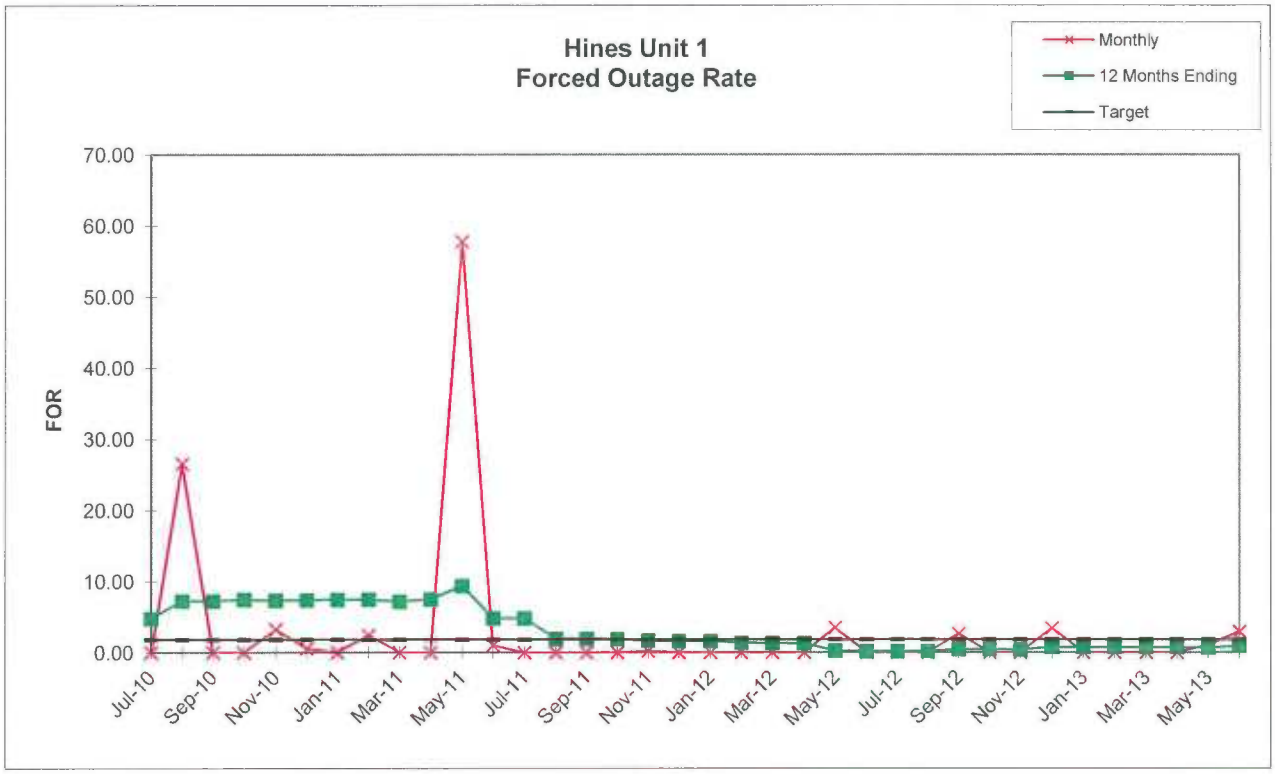
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	4.76	7.23	7.21	7.41	7.29	7.34	7.40	7.43	7.13	7.43	9.33	4.80	4.80	1.91	1.91	1.85	1.67	1.60
MOR	1.80	1.85	1.84	1.90	1.93	1.94	2.75	3.15	1.95	1.35	1.50	1.43	1.43	1.39	1.39	1.34	1.40	1.39
PFOR	0.59	0.61	0.61	1.15	0.98	0.98	1.02	0.74	0.73	0.79	0.92	1.27	1.27	1.84	2.23	1.61	1.65	1.65
PMOR	0.01	0.01	0.01	0.01	0.01	1.01	1.01	0.99	0.94	1.02	1.16	1.10	1.12	1.13	1.13	1.11	1.16	0.10
EUOR	6.96	9.39	9.37	10.10	9.86	10.82	11.60	11.69	10.33	10.25	12.42	8.32	8.34	6.11	6.50	5.77	5.74	4.66
EUOF	6.47	8.73	8.73	9.16	8.76	9.61	10.31	10.68	9.72	8.80	9.82	6.58	6.59	4.83	5.13	4.71	4.50	3.65
POF	6.81	6.81	6.81	9.29	11.14	11.14	11.14	8.66	5.95	14.17	20.98	20.98	20.98	20.98	20.98	18.50	21.17	21.17
EAF	86.72	84.46	84.46	81.55	80.10	79.25	78.55	80.66	84.33	77.03	69.20	72.44	72.42	74.19	73.88	76.79	74.34	75.19

Hines
Unit 1

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	696.00	743.00	312.78	321.13	720.00	744.00	719.00	701.03	744.00	721.00	718.58	744.00	672.00	743.00	291.80	567.27	699.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	407.22	422.87	0.00	0.00	25.00	18.97	0.00	0.00	25.42	0.00	0.00	0.00	428.20	176.73	21.00
POH	0.00	0.00	0.00	407.22	187.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	428.20	170.68	0.00
FOH	0.00	0.00	0.00	0.00	11.65	0.00	0.00	0.00	18.97	0.00	0.00	25.42	0.00	0.00	0.00	0.00	6.05	21.00
MOH	0.00	0.00	0.00	0.00	223.55	0.00	0.00	25.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	41.22	0.00	0.00	1.45	0.00	1.87	0.00	21.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.58
LRPF	227.98	0.00	0.00	174.00	0.00	241.64	0.00	292.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	229.03
EFOH	20.34	0.00	0.00	0.55	0.00	0.98	0.00	13.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.17
PMOH	0.00	0.00	1.40	0.00	45.25	0.00	0.00	1.32	1.98	0.00	42.72	0.00	0.00	0.00	0.00	0.00	0.00	1.62
LRPM	0.00	0.00	199.00	0.00	297.00	0.00	0.00	198.50	130.22	0.00	214.64	0.00	0.00	0.00	0.00	0.00	0.00	198.59
EMOH	0.00	0.00	0.60	0.00	29.09	0.00	0.00	0.57	0.56	0.00	19.85	0.00	0.00	0.00	0.00	0.00	0.00	0.70
NPC	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00

MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.00	0.00	0.00	3.50	0.00	0.00	0.00	2.63	0.00	0.00	3.42	0.00	0.00	0.00	0.00	1.06	2.92
MOR	0.00	0.00	0.00	0.00	41.04	0.00	0.00	3.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	2.73	0.00	0.00	0.17	0.00	0.14	0.00	1.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.03
PMOR	0.00	0.00	0.08	0.00	9.06	0.00	0.00	0.08	0.08	0.00	2.75	0.00	0.00	0.00	0.00	0.00	0.00	0.10
EUOR	2.73	0.00	0.08	0.17	47.51	0.14	0.00	5.30	2.71	0.00	2.75	3.42	0.00	0.00	0.00	0.00	1.06	4.98
EUOF	2.73	0.00	0.08	0.08	35.52	0.14	0.00	5.30	2.71	0.00	2.75	3.42	0.00	0.00	0.00	0.00	0.81	4.98
POF	0.00	0.00	0.00	56.56	25.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.47	22.94	0.00
EAF	97.27	100.00	99.92	43.37	39.25	99.86	100.00	94.70	97.29	100.00	97.25	96.58	100.00	100.00	100.00	40.53	76.25	95.02

12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	1.59	1.35	1.32	1.27	0.26	0.16	0.16	0.16	0.42	0.42	0.39	0.71	0.71	0.71	0.71	0.71	0.62	0.88
MOR	0.53	0.00	0.00	0.00	2.89	2.89	2.89	3.21	3.22	3.22	3.05	3.06	3.06	3.07	3.07	3.07	0.31	0.31
PFOR	1.87	1.71	1.66	1.60	1.51	1.18	1.18	0.83	0.48	0.48	0.45	0.45	0.20	0.20	0.20	0.19	0.18	0.35
PMOR	0.10	0.10	0.11	0.10	0.47	0.47	0.45	0.43	0.43	0.42	0.64	0.64	0.64	0.64	0.64	0.64	0.26	0.27
EUOR	4.03	3.14	3.07	2.95	5.05	4.64	4.63	4.58	4.49	4.48	4.46	4.77	4.53	4.54	4.53	4.54	1.36	1.79
EUOF	3.15	2.46	2.45	2.46	4.46	4.10	4.08	4.04	3.96	3.95	4.16	4.45	4.22	4.23	4.22	4.22	1.27	1.67
POF	21.17	21.11	19.49	15.93	11.28	11.28	11.28	11.28	11.28	11.28	6.77	6.77	6.77	6.79	6.79	7.03	6.84	6.84
EAF	75.68	76.43	78.05	81.61	84.26	84.63	84.64	84.68	84.77	84.77	89.07	88.78	89.01	88.98	88.98	88.75	91.89	91.50


Hines Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
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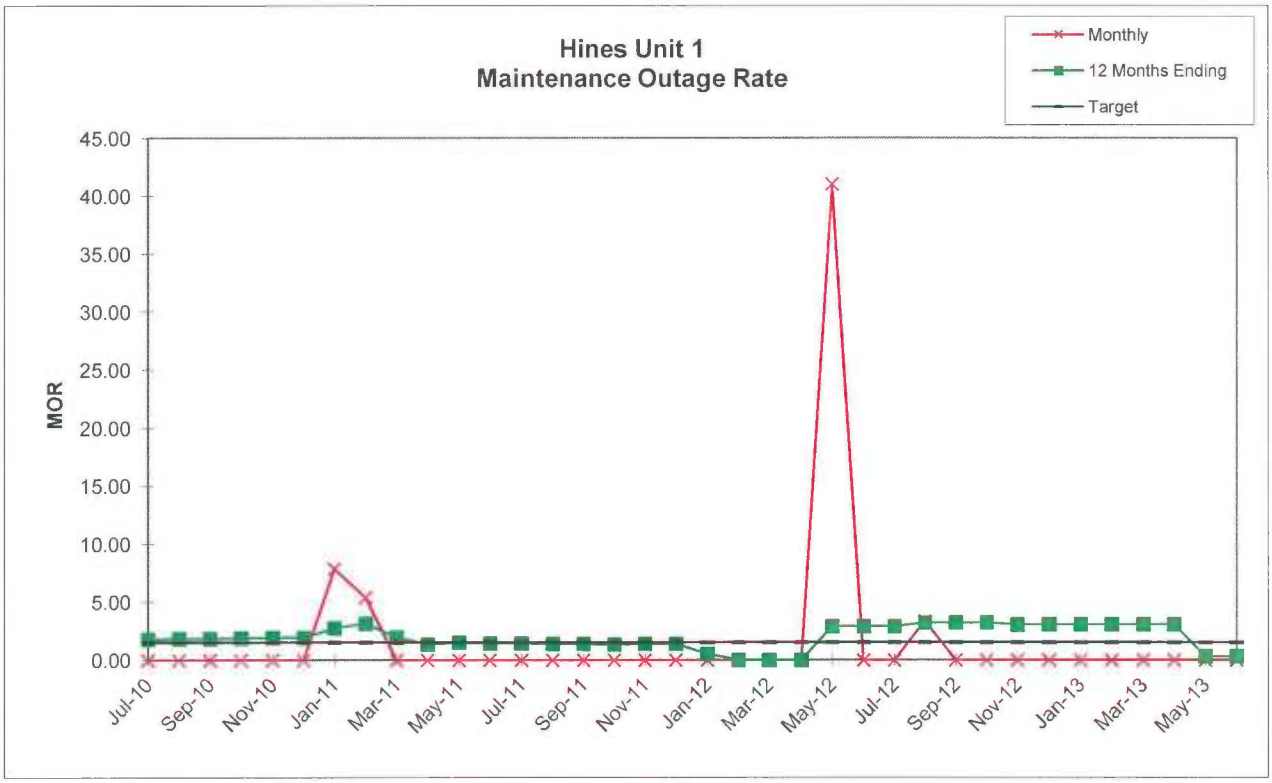
Hines Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
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Jul-10
Sep-10
Nov-10
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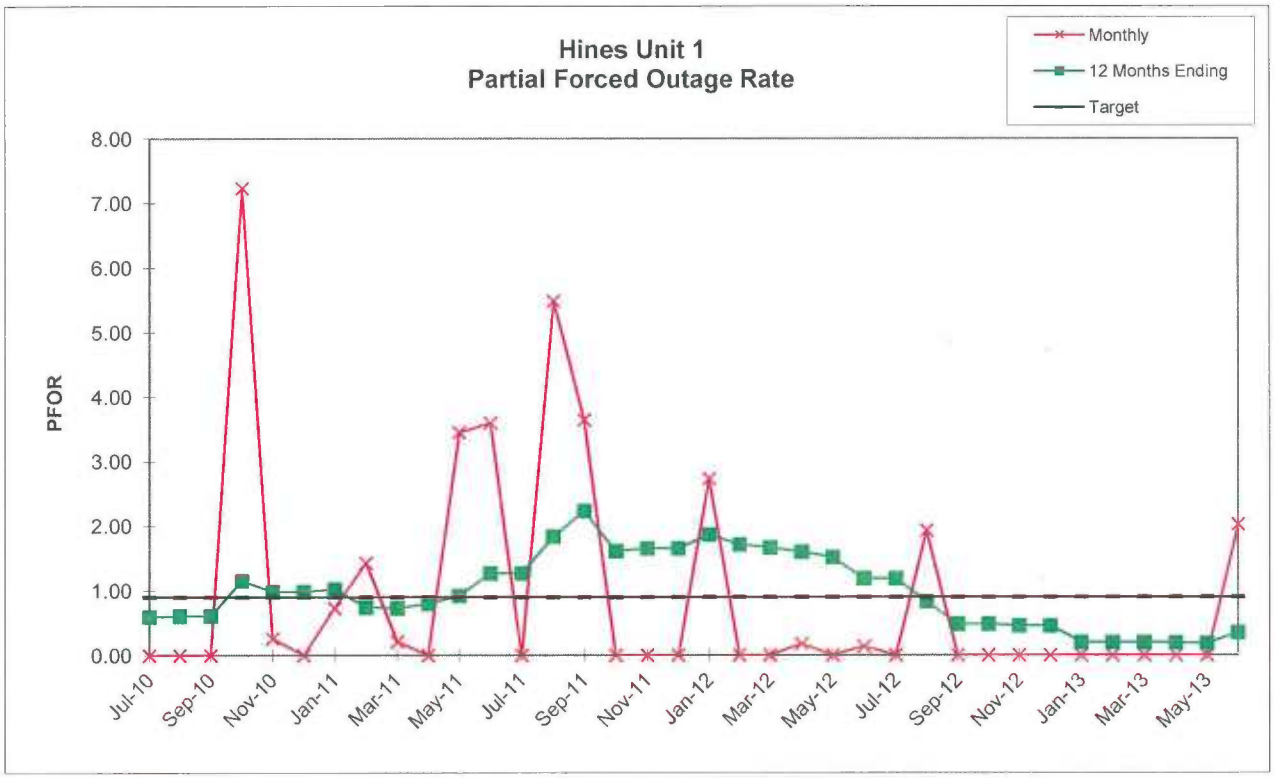
Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
8.00
7.00
6.00
5.00
4.00
3.00
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Jul-10
Sep-10
Nov-10
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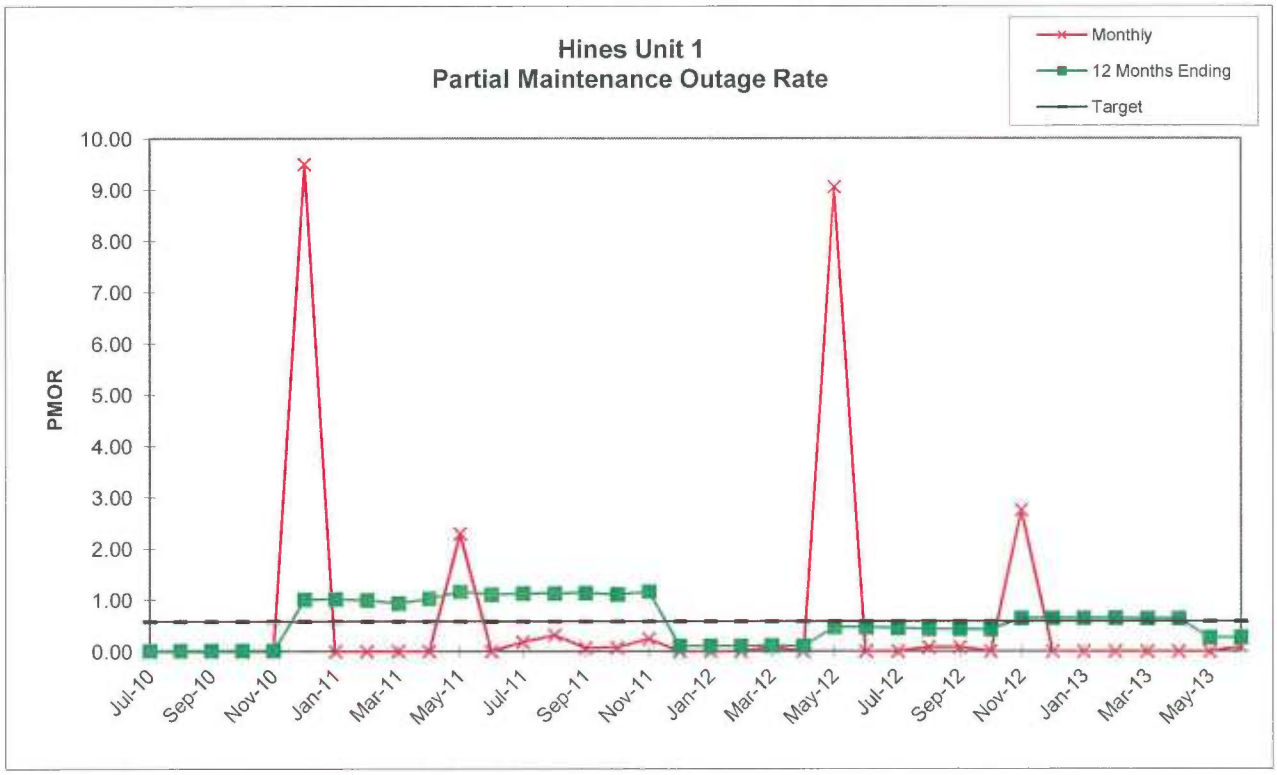
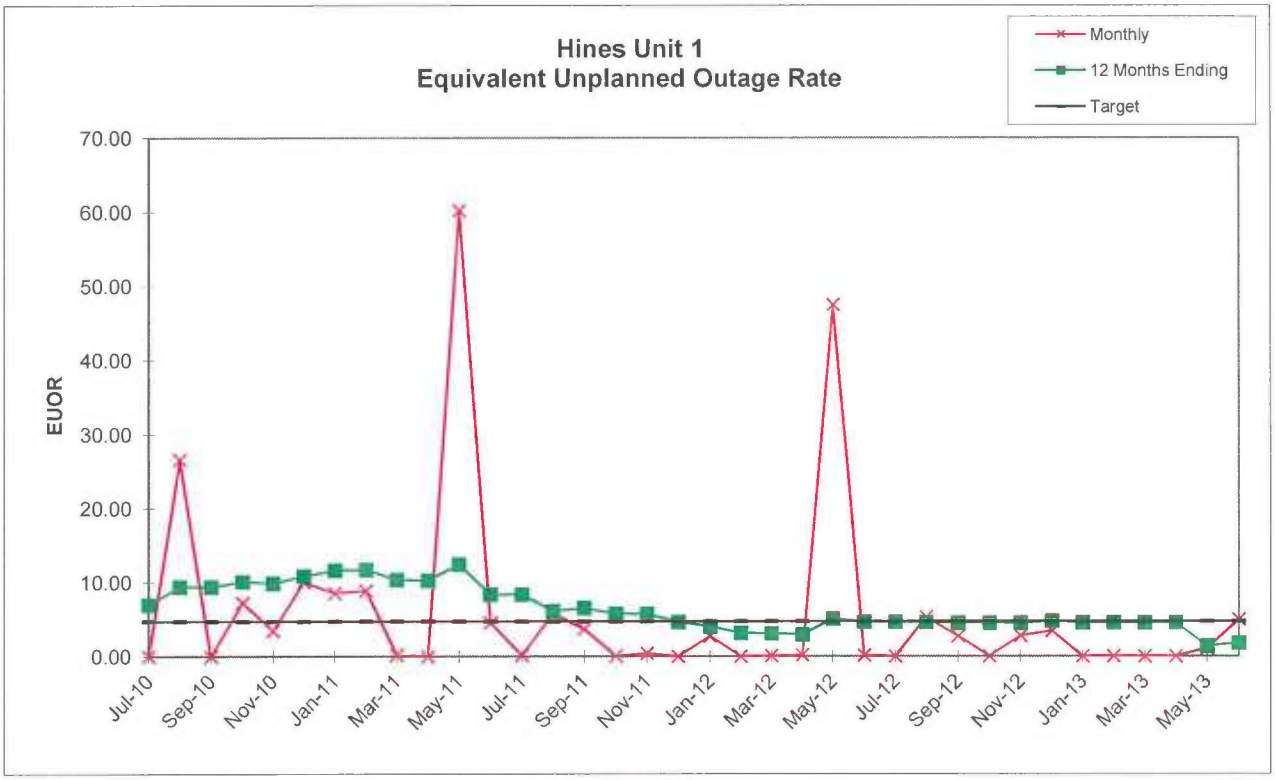
Mar-13
May-13


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
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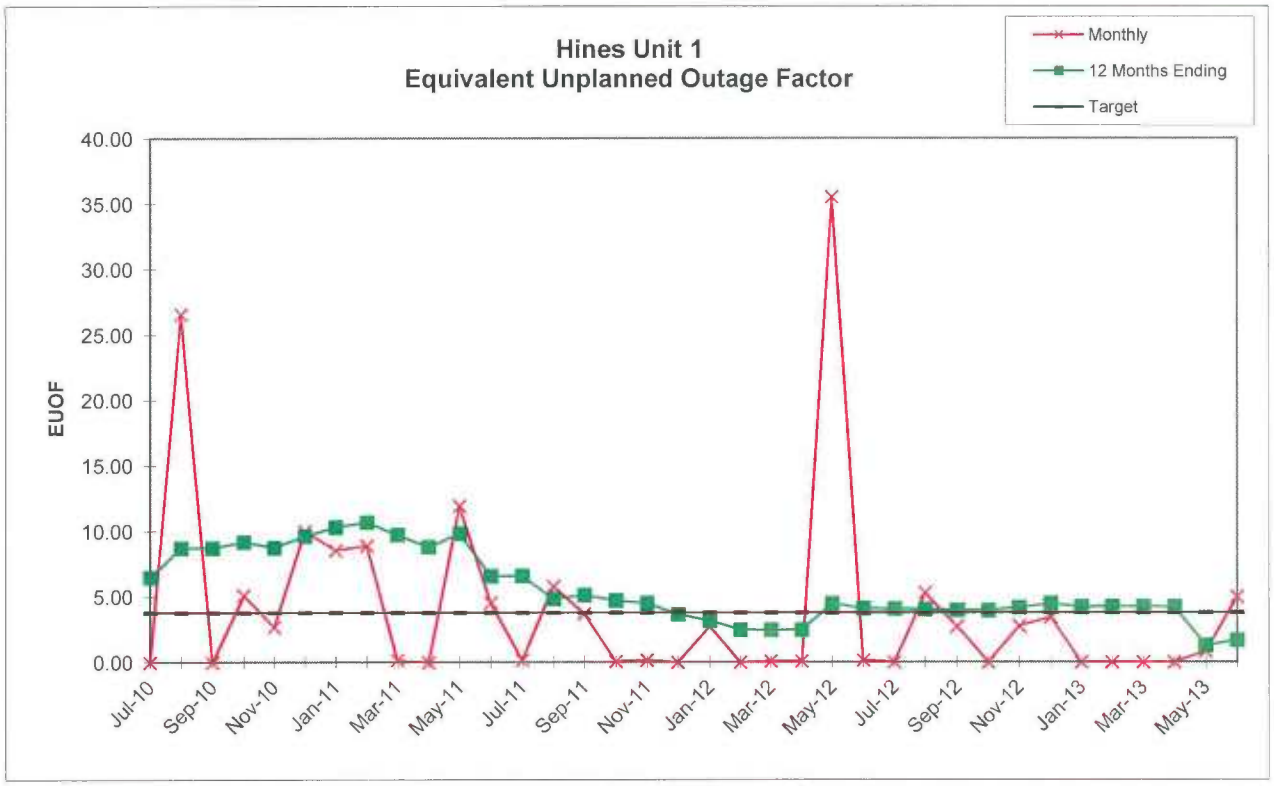
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Hines
Unit 2

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	668.40	744.00	720.00	744.00	721.00	526.67	744.00	671.43	0.00	509.53	744.00	720.00	744.00	744.00	720.00	744.00	267.13	523.58
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	152.97
UH	75.60	0.00	0.00	0.00	0.00	217.33	0.00	0.57	743.00	210.47	0.00	0.00	0.00	0.00	0.00	0.00	453.87	67.45
POH	0.00	0.00	0.00	0.00	0.00	173.33	0.00	0.57	743.00	210.47	0.00	0.00	0.00	0.00	0.00	0.00	453.87	1.80
FOH	0.00	0.00	0.00	0.00	0.00	44.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	75.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.65
PFOH	0.00	0.00	0.00	0.00	0.00	32.22	0.00	4.37	0.00	3.10	0.00	0.00	0.00	4.98	18.12	0.00	0.00	62.78
LRPF	0.00	0.00	0.00	0.00	0.00	251.56	0.00	229.82	0.00	271.22	0.00	0.00	0.00	280.19	281.33	0.00	0.00	222.18
EFOH	0.00	0.00	0.00	0.00	0.00	16.54	0.00	2.05	0.00	1.72	0.00	0.00	0.00	2.85	10.40	0.00	0.00	28.47
PMOH	0.00	0.00	0.00	45.77	422.00	0.00	66.10	0.00	0.00	176.44	16.67	0.00	2.38	14.59	1.79	0.00	0.00	26.45
LRPM	0.00	0.00	0.00	239.98	240.00	0.00	230.00	0.00	0.00	245.99	245.95	0.00	158.22	157.93	157.41	0.00	0.00	195.00
EMOH	0.00	0.00	0.00	22.42	206.69	0.00	31.03	0.00	0.00	88.58	8.37	0.00	0.77	4.70	0.58	0.00	0.00	10.53
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	0.00	0.00	0.00	0.00	0.00	7.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	10.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.14
PFOR	0.00	0.00	0.00	0.00	0.00	3.14	0.00	0.31	0.00	0.34	0.00	0.00	0.00	0.38	1.44	0.00	0.00	5.44
PMOR	0.00	0.00	0.00	3.01	28.67	0.00	4.17	0.00	0.00	17.38	1.12	0.00	0.10	0.63	0.08	0.00	0.00	2.01
EUOR	10.16	0.00	0.00	3.01	28.67	10.61	4.17	0.31	0.00	17.72	1.12	0.00	0.10	1.01	1.52	0.00	0.00	17.76
EUOF	10.16	0.00	0.00	3.01	28.67	8.14	4.17	0.31	0.00	12.54	1.12	0.00	0.10	1.01	1.52	0.00	0.00	14.06
POF	0.00	0.00	0.00	0.00	0.00	23.30	0.00	0.08	100.00	29.23	0.00	0.00	0.00	0.00	0.00	0.00	62.95	0.24
EAF	89.84	100.00	100.00	96.99	71.33	68.57	95.83	99.61	0.00	58.23	98.88	100.00	99.90	98.99	98.48	100.00	37.05	85.69

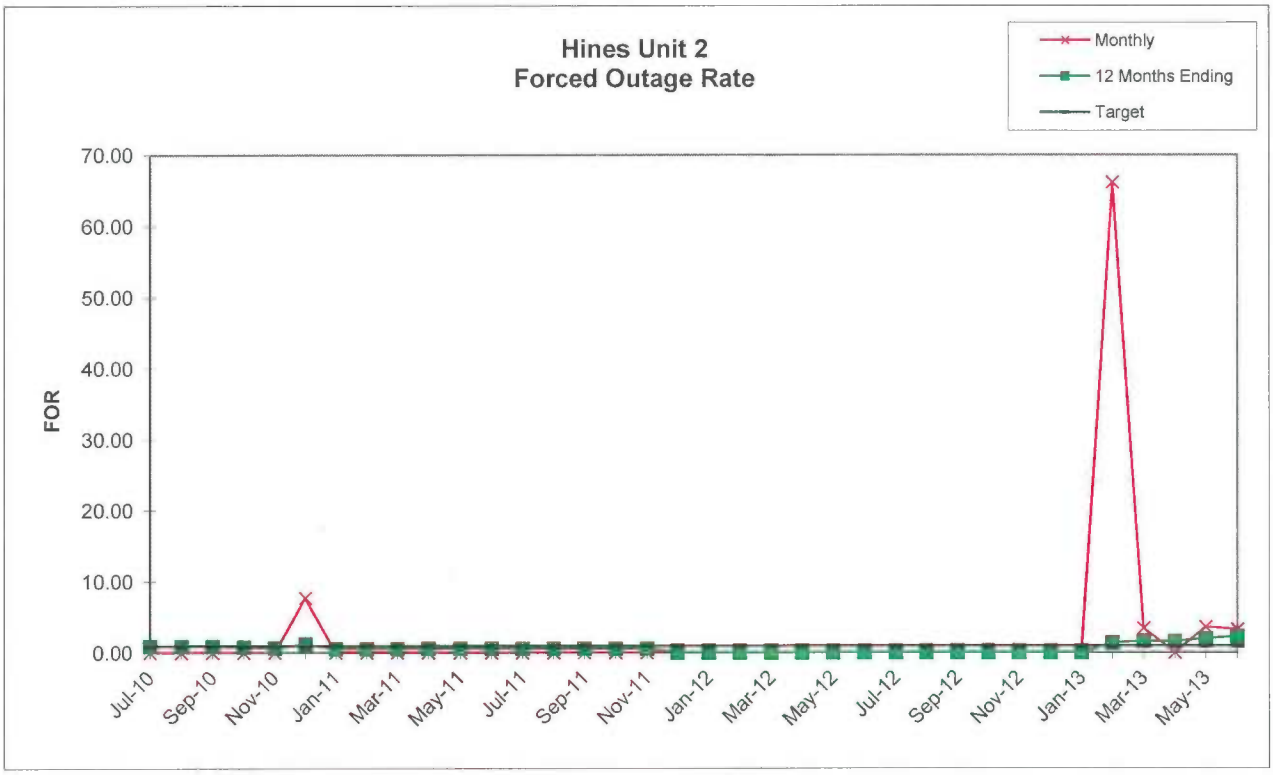
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	0.91	0.91	0.91	0.81	0.67	1.22	0.54	0.54	0.57	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.61	0.00
MOR	0.97	0.97	0.97	0.97	0.92	0.94	0.93	0.93	0.97	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.91
PFOR	0.62	0.62	0.00	0.00	0.00	0.21	0.21	0.23	0.24	0.27	0.27	0.27	0.27	0.31	0.44	0.44	0.47	0.64
PMOR	2.93	2.93	2.93	2.11	2.81	2.87	3.24	3.24	3.37	4.64	4.75	4.75	4.72	4.78	4.79	4.49	1.88	2.03
EUOR	5.35	5.35	4.73	3.83	4.33	5.15	4.86	4.89	5.08	6.40	6.51	6.51	5.53	5.63	5.77	5.48	2.95	3.55
EUOF	4.81	4.81	4.26	3.45	4.10	4.79	4.52	4.55	4.55	5.58	5.67	5.67	4.82	4.91	5.03	4.77	2.42	2.92
POF	9.91	9.91	9.91	9.91	5.22	6.84	6.84	6.85	10.47	12.87	12.87	12.87	12.87	12.87	12.87	12.87	18.05	16.09
EAF	85.28	85.28	85.83	86.64	90.68	88.37	88.64	88.61	84.99	81.55	81.46	81.46	82.31	82.23	82.10	82.36	79.53	80.99

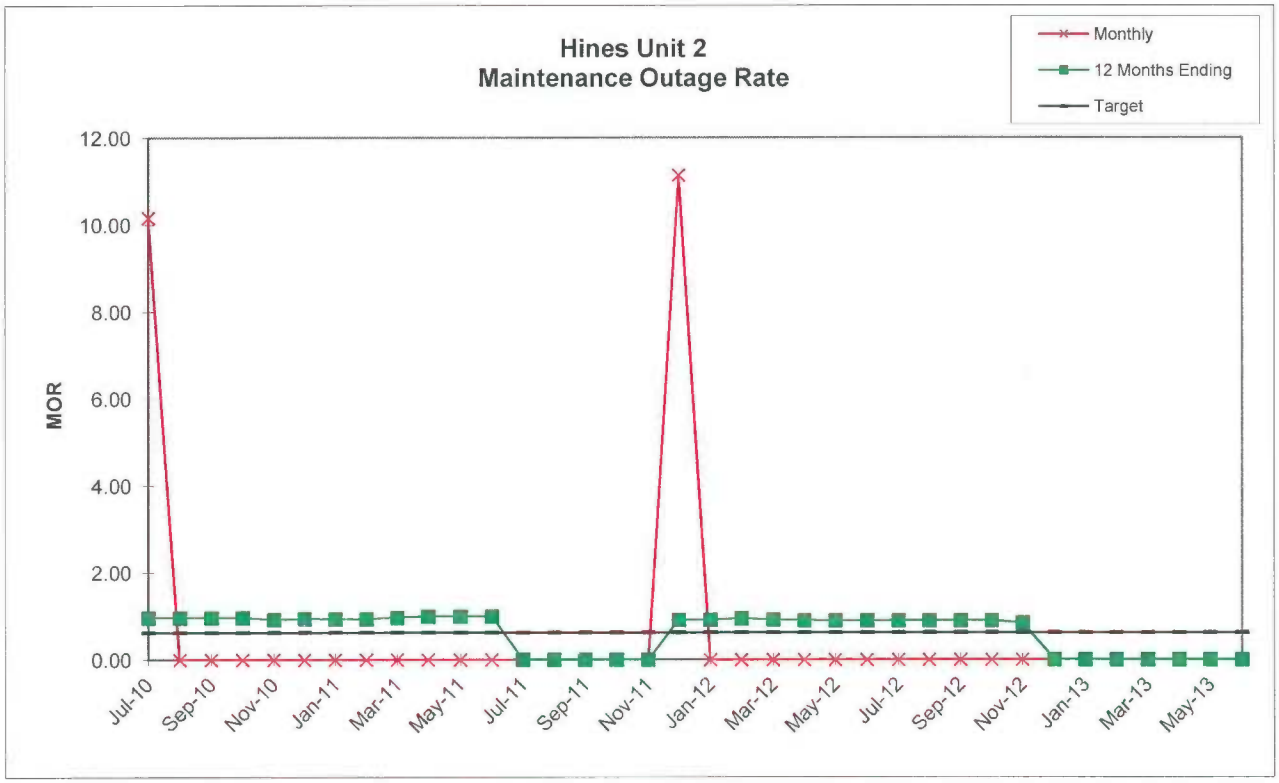
Hines
Unit 2

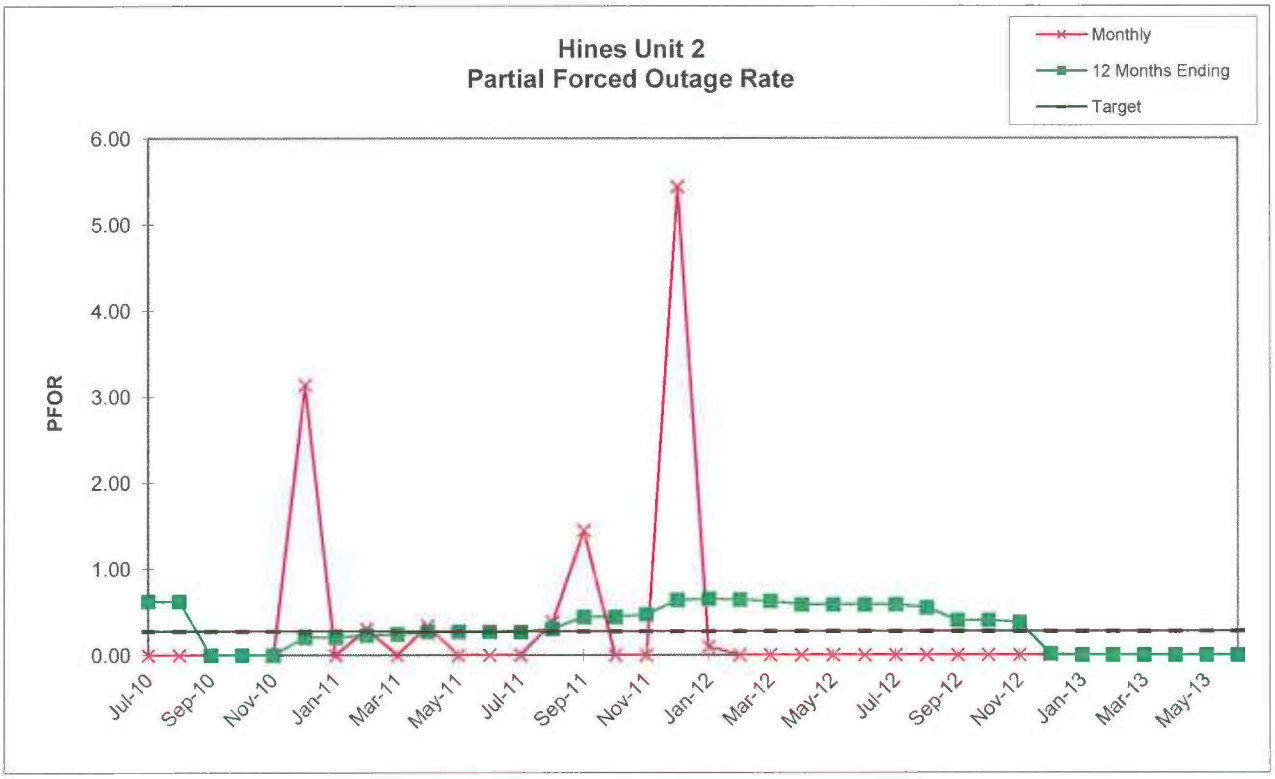
	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	403.20	217.77	680.65	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	335.82	51.62	717.42	720.00	717.17	696.45
RSH	0.00	292.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	408.18	24.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	525.23	39.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	596.39	25.58	0.00	26.83	23.55
POH	0.00	0.00	525.23	39.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	495.57	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.82	25.58	0.00	26.83	23.55
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	265.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	3.27	0.00	0.00	12.05	2.55	2.40	0.00	1.95	1.98	0.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	1.50
LRPM	149.04	0.00	0.00	309.72	127.00	127.00	0.00	147.00	158.27	0.00	170.29	0.00	0.00	0.00	0.00	0.00	0.00	127.00
EMOH	0.99	0.00	0.00	7.62	0.66	0.62	0.00	0.59	0.64	0.00	0.69	0.00	0.00	0.00	0.00	0.00	0.00	0.39
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

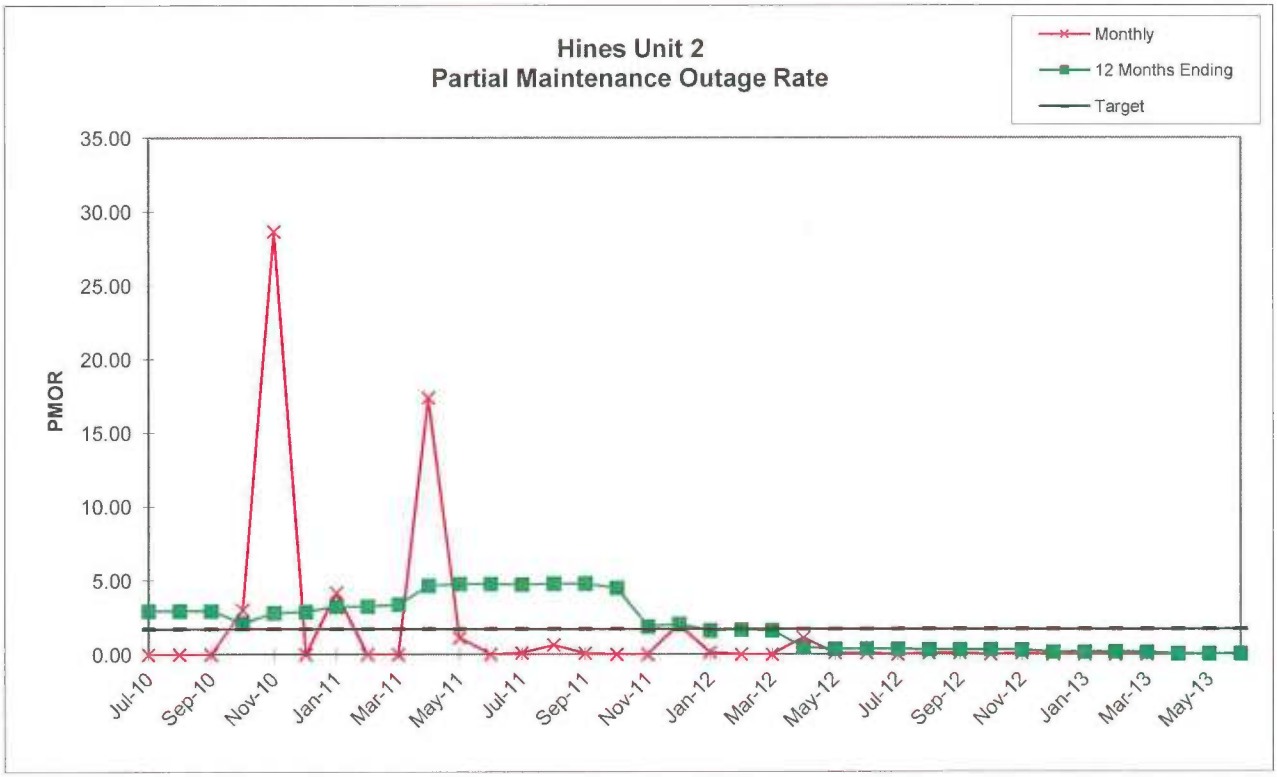
MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.14	3.44	0.00	3.61	3.27
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.13	0.00	0.00	1.12	0.09	0.09	0.00	0.08	0.09	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.06
EUOR	0.23	0.00	0.00	1.12	0.09	0.09	0.00	0.08	0.09	0.00	0.10	0.00	0.00	66.14	3.44	0.00	3.61	3.32
EUOF	0.23	0.00	0.00	1.06	0.09	0.09	0.00	0.08	0.09	0.00	0.10	0.00	0.00	15.00	3.44	0.00	3.61	3.32
POF	0.00	0.00	70.69	5.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.75	0.00	0.00	0.00	0.00
EAF	99.77	100.00	29.31	93.48	99.91	99.91	100.00	99.92	99.91	100.00	99.90	100.00	100.00	11.25	96.56	100.00	96.39	96.68

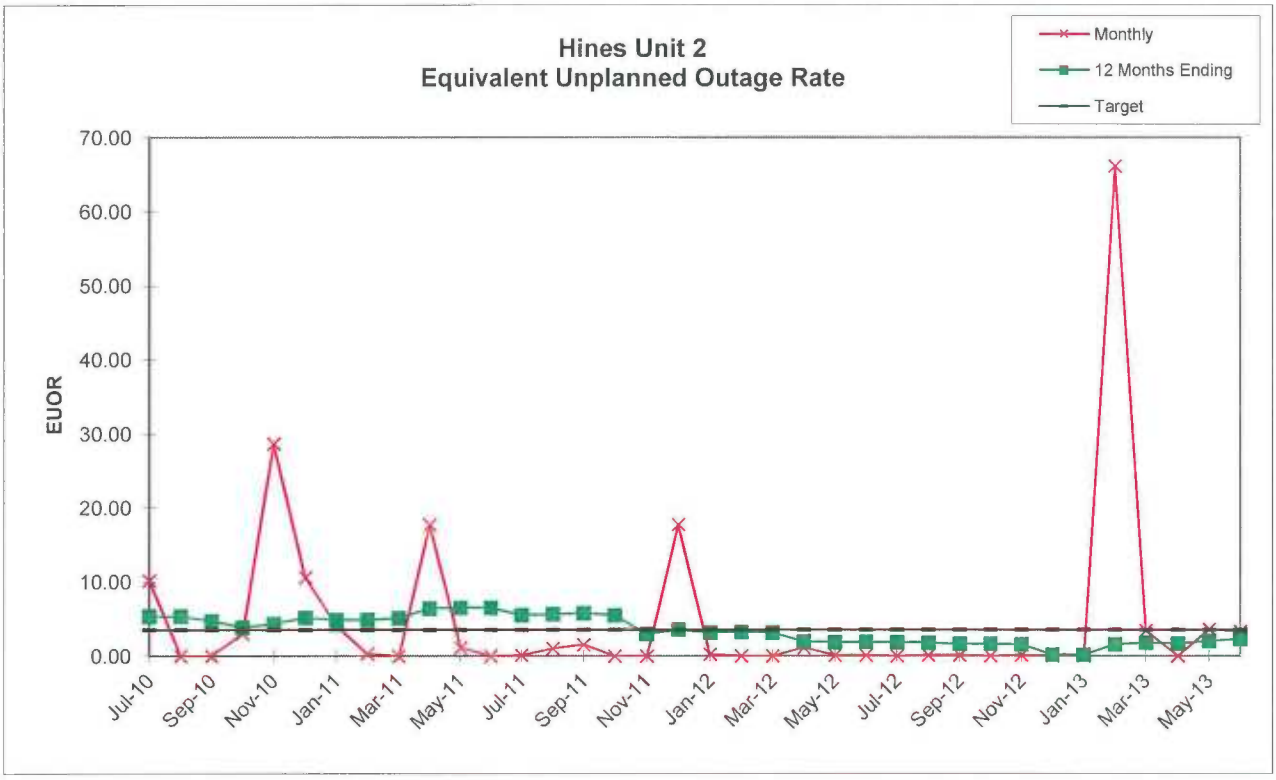
12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.39	1.62	1.61	1.96	2.26
MOR	0.91	0.95	0.92	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.65	0.64	0.62	0.59	0.59	0.59	0.59	0.55	0.40	0.40	0.38	0.01	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	1.61	1.67	1.62	0.46	0.36	0.36	0.35	0.30	0.30	0.30	0.29	0.15	0.14	0.15	0.14	0.04	0.03	0.03
EUOR	3.15	3.24	3.14	1.94	1.83	1.84	1.83	1.73	1.59	1.59	1.51	0.16	0.14	1.54	1.76	1.65	1.99	2.29
EUOF	2.58	2.55	2.55	1.61	1.52	1.53	1.52	1.44	1.33	1.33	1.33	0.14	0.12	1.27	1.57	1.48	1.78	2.04
POF	16.09	16.04	13.56	11.61	11.61	11.61	11.61	11.61	11.61	11.61	6.45	6.43	6.43	12.10	6.11	5.66	5.66	5.66
EAF	81.32	81.40	83.88	86.77	86.86	86.85	86.86	86.94	87.06	87.06	92.22	93.43	93.45	86.62	92.33	92.86	92.56	92.30


Hines Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
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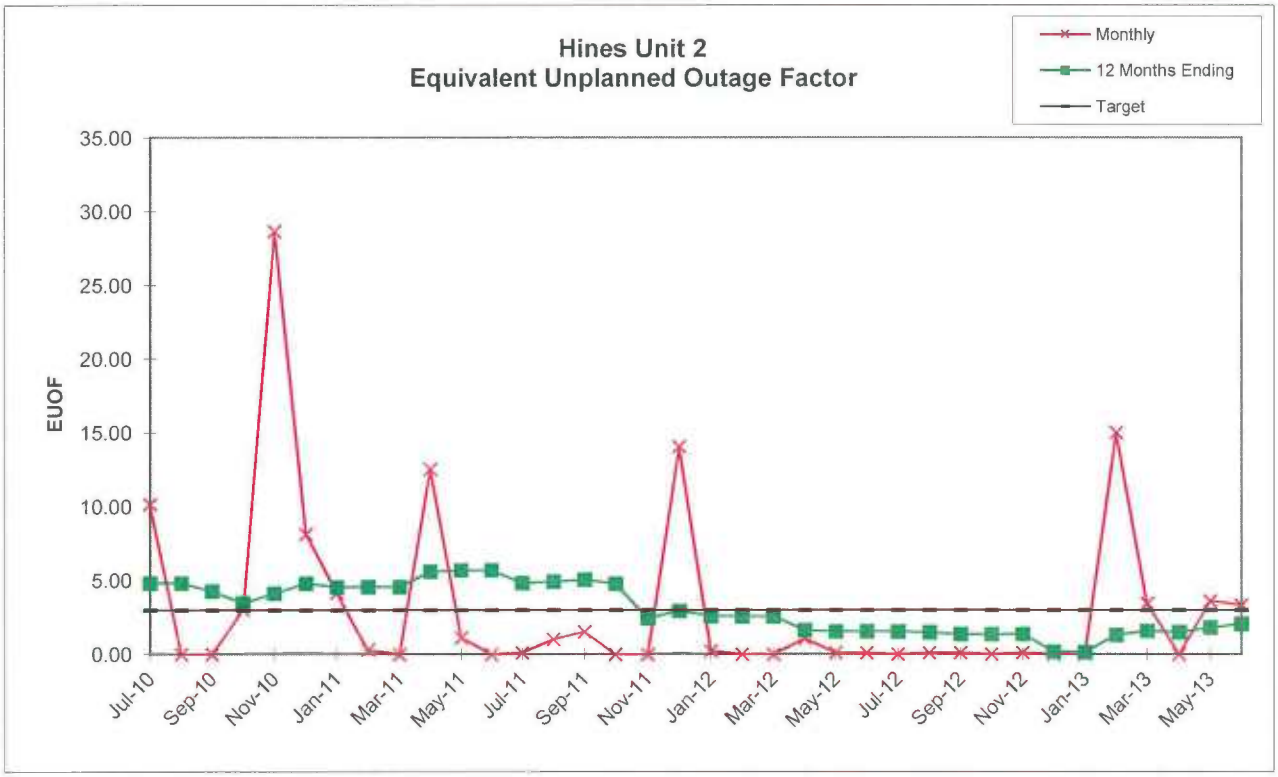
May-13


Hines Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Hines
Unit 3

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	744.00	744.00	712.43	744.00	376.50	744.00	744.00	672.00	743.00	480.43	434.68	720.00	744.00	744.00	681.42	744.00	601.43	502.13
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	7.57	0.00	367.50	0.00	0.00	0.00	0.00	239.57	309.32	0.00	0.00	0.00	38.58	0.00	119.57	241.87
POH	0.00	0.00	0.00	0.00	367.50	0.00	0.00	0.00	0.00	239.57	309.32	0.00	0.00	0.00	0.00	0.00	119.57	241.87
FOH	0.00	0.00	7.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.05	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.53	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	6.47	0.00	0.00	0.00	0.00	1.68	3.10	0.00	18.37	7.92	0.22	0.00	6.75
LRPF	0.00	0.00	0.00	0.00	0.00	207.89	0.00	0.00	0.00	0.00	228.45	158.00	0.00	124.98	240.81	123.09	0.00	125.00
EFOH	0.00	0.00	0.00	0.00	0.00	2.76	0.00	0.00	0.00	0.00	0.79	1.00	0.00	4.70	3.91	0.06	0.00	1.73
PMOH	0.00	0.00	0.00	0.00	0.00	21.12	35.68	0.00	0.00	0.00	0.00	0.00	1.00	8.48	1.08	1.02	3.21	18.37
LRPM	0.00	0.00	0.00	0.00	0.00	207.97	223.02	0.00	0.00	0.00	0.00	0.00	125.00	125.05	125.39	124.59	125.26	126.52
EMOH	0.00	0.00	0.00	0.00	0.00	9.00	16.31	0.00	0.00	0.00	0.00	0.00	0.26	2.17	0.28	0.26	0.82	4.76
NPC	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	0.00	0.00	1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.09	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00	0.00	0.00	0.18	0.14	0.00	0.63	0.57	0.01	0.00	0.34
PMOR	0.00	0.00	0.00	0.00	0.00	1.21	2.19	0.00	0.00	0.00	0.00	0.00	0.03	0.29	0.04	0.04	0.14	0.95
EUOR	0.00	0.00	1.05	0.00	0.00	1.58	2.19	0.00	0.00	0.00	0.18	0.14	0.03	0.92	5.94	0.04	0.14	1.29
EUOF	0.00	0.00	1.05	0.00	0.00	1.58	2.19	0.00	0.00	0.00	0.11	0.14	0.03	0.92	5.94	0.04	0.11	0.87
POF	0.00	0.00	0.00	0.00	50.97	0.00	0.00	0.00	0.00	33.27	41.58	0.00	0.00	0.00	0.00	0.00	16.58	32.51
EAF	100.00	100.00	98.95	100.00	49.03	98.42	97.81	100.00	100.00	66.73	58.32	99.86	99.97	99.08	94.06	99.96	83.30	66.62

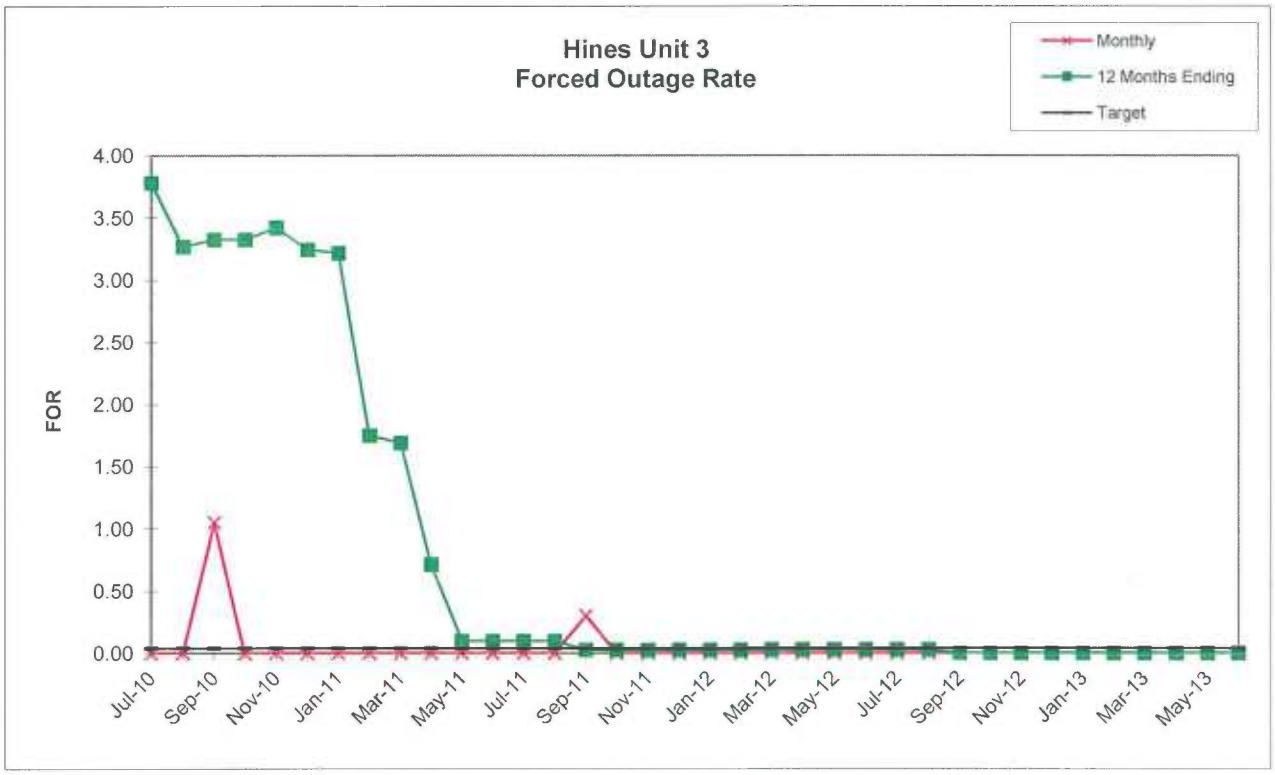
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	3.78	3.27	3.32	3.32	3.42	3.24	3.22	1.75	1.69	0.71	0.10	0.10	0.10	0.10	0.03	0.03	0.03	0.03
MOR	1.31	1.30	1.31	1.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.46	0.46	0.45	0.47
PFOR	0.24	0.24	0.24	0.24	0.25	0.27	0.27	0.27	0.26	0.13	0.05	0.06	0.06	0.12	0.17	0.17	0.16	0.16
PMOR	3.87	3.84	3.84	3.67	0.51	0.29	0.33	0.32	0.31	0.31	0.32	0.32	0.33	0.35	0.36	0.36	0.36	0.32
EUOR	8.90	8.38	8.44	8.28	4.15	3.79	3.79	2.33	2.25	1.15	0.46	0.48	0.48	0.57	1.01	1.02	1.00	0.96
EUOF	8.03	7.58	7.64	7.49	3.59	3.46	3.46	2.12	2.12	1.08	0.42	0.43	0.43	0.51	0.91	0.91	0.92	0.86
POF	6.83	6.83	6.83	6.83	11.02	9.03	9.03	9.03	5.74	6.93	10.46	10.46	10.46	10.46	10.46	10.46	7.63	10.39
EAF	85.14	85.59	85.54	85.68	85.39	87.51	87.51	88.85	92.14	91.99	89.12	89.11	89.11	89.03	88.63	88.62	91.45	88.74

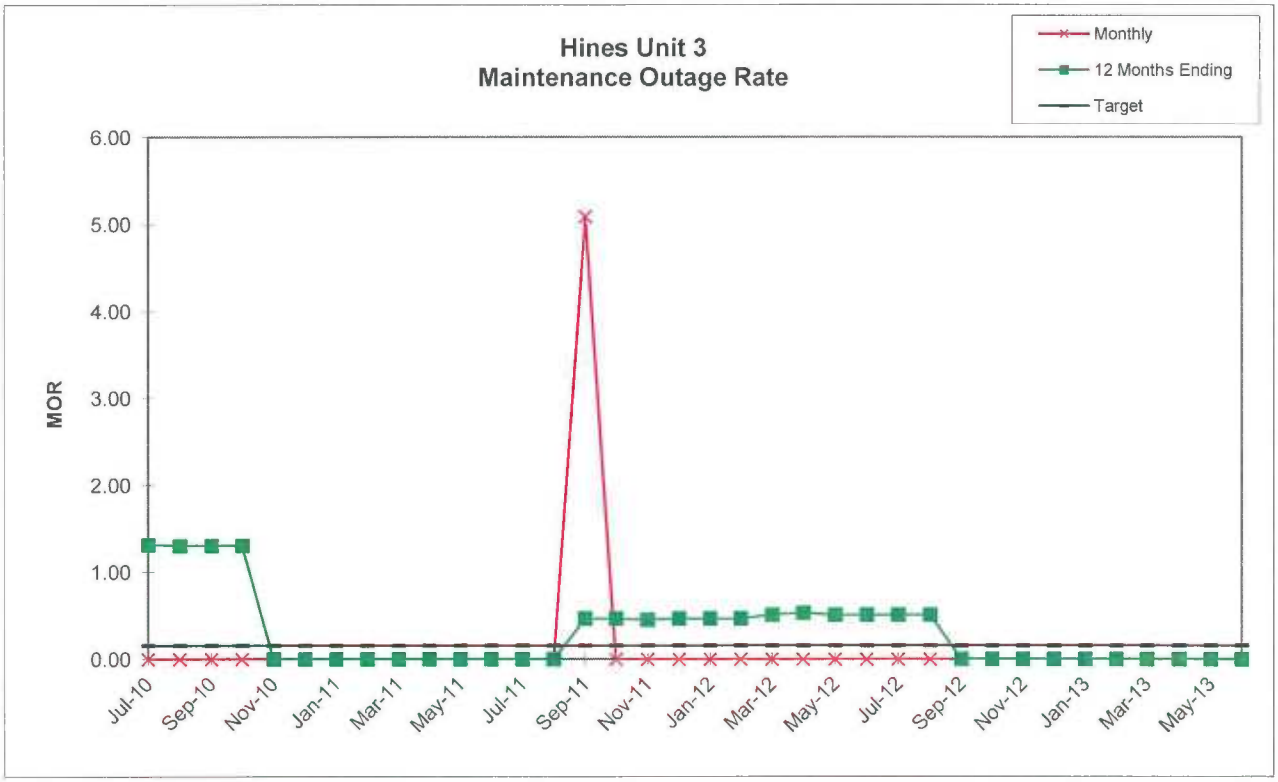
Hines
Unit 3

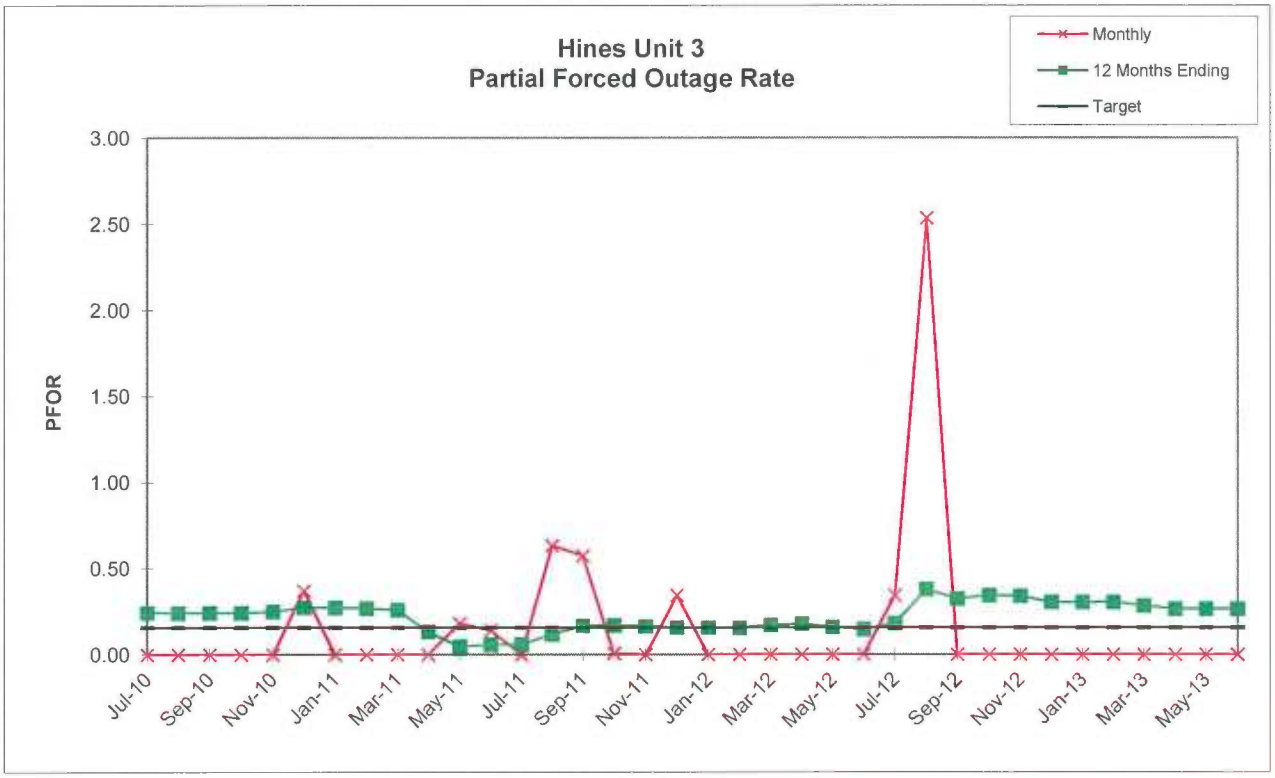
	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	744.00	696.00	50.07	191.12	744.00	720.00	744.00	744.00	720.00	287.82	688.68	744.00	744.00	672.00	571.35	720.00	744.00	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	692.93	528.88	0.00	0.00	0.00	0.00	0.00	456.18	32.32	0.00	0.00	0.00	171.65	0.00	0.00	0.00
POH	0.00	0.00	692.93	528.88	0.00	0.00	0.00	0.00	0.00	456.18	32.32	0.00	0.00	0.00	171.65	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	3.78	28.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	328.29	318.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	2.54	18.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	2.05	0.00	0.00	0.00	1.18	1.25	0.00	0.00	0.00	4.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	125.00	0.00	0.00	0.00	125.36	125.00	0.00	0.00	0.00	318.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.53	0.00	0.00	0.00	0.30	0.32	0.00	0.00	0.00	3.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00

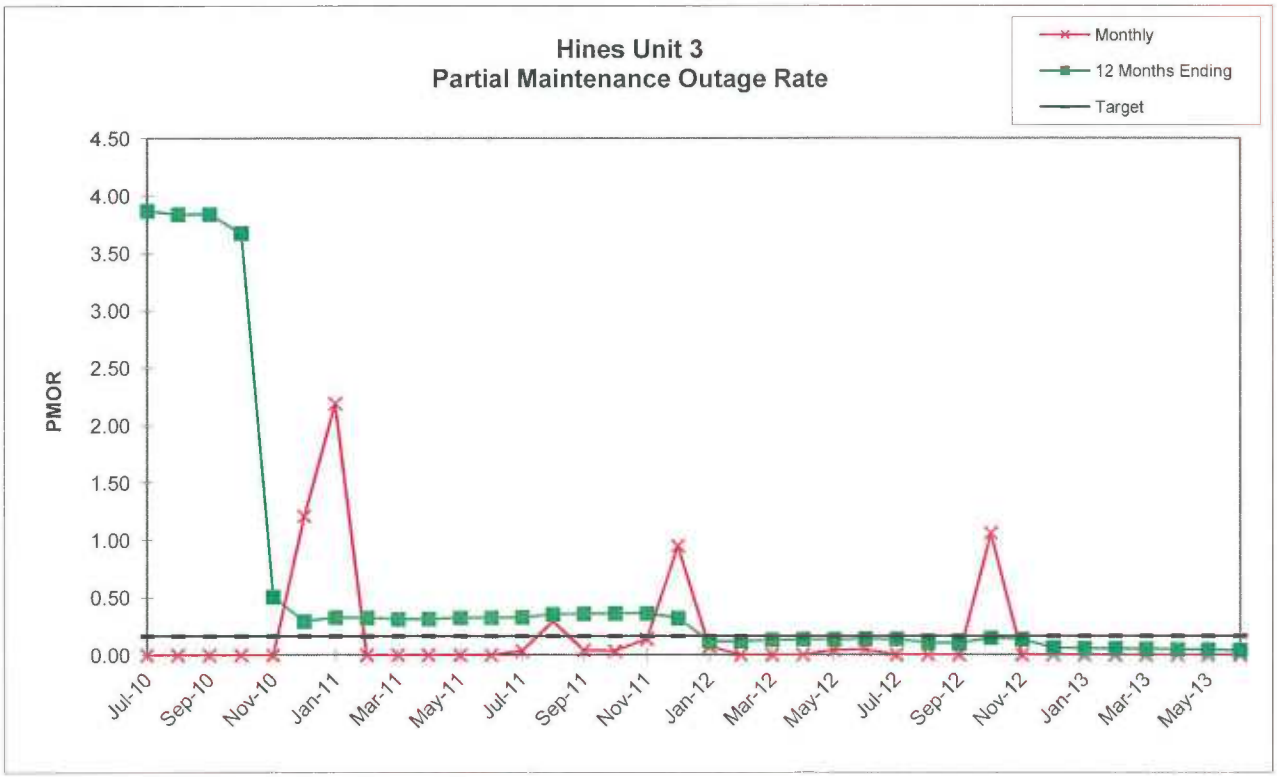
MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.34	2.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.07	0.00	0.00	0.00	0.04	0.04	0.00	0.00	0.00	1.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.07	0.00	0.00	0.00	0.04	0.04	0.34	2.53	0.00	1.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOF	0.07	0.00	0.00	0.00	0.04	0.04	0.34	2.53	0.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
POF	0.00	0.00	93.26	73.46	0.00	0.00	0.00	0.00	0.00	61.31	4.48	0.00	0.00	0.00	23.10	0.00	0.00	0.00
EAF	99.93	100.00	6.74	26.54	99.96	99.96	99.66	97.47	100.00	38.28	95.52	100.00	100.00	100.00	76.90	100.00	100.00	100.00

12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.47	0.46	0.51	0.53	0.51	0.51	0.51	0.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.16	0.16	0.17	0.18	0.16	0.15	0.18	0.38	0.32	0.34	0.34	0.30	0.30	0.30	0.28	0.26	0.26	0.26
PMOR	0.12	0.12	0.13	0.13	0.13	0.14	0.13	0.10	0.10	0.15	0.13	0.06	0.05	0.05	0.05	0.05	0.04	0.04
EUOR	0.76	0.76	0.83	0.87	0.82	0.81	0.85	1.01	0.42	0.49	0.47	0.36	0.35	0.36	0.33	0.31	0.31	0.30
EUOF	0.68	0.68	0.68	0.68	0.68	0.67	0.69	0.83	0.34	0.37	0.37	0.29	0.29	0.29	0.29	0.29	0.28	0.28
POF	10.39	10.36	18.25	21.55	18.02	18.02	18.02	18.02	18.02	23.22	22.22	19.47	19.47	19.52	13.57	7.54	7.54	7.54
EAF	88.92	88.96	81.07	77.77	81.30	81.31	81.28	81.15	81.63	76.41	77.41	80.24	80.24	80.19	86.14	92.18	92.18	92.18


Hines Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
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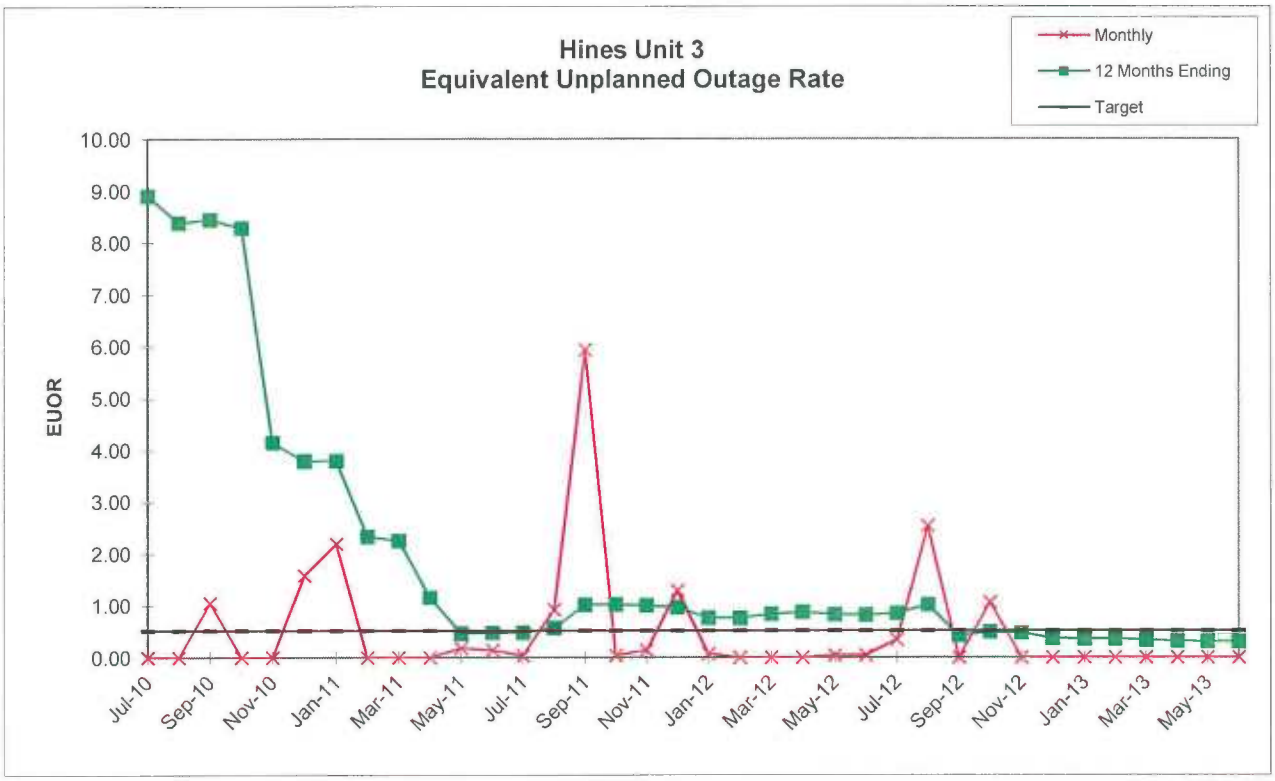
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
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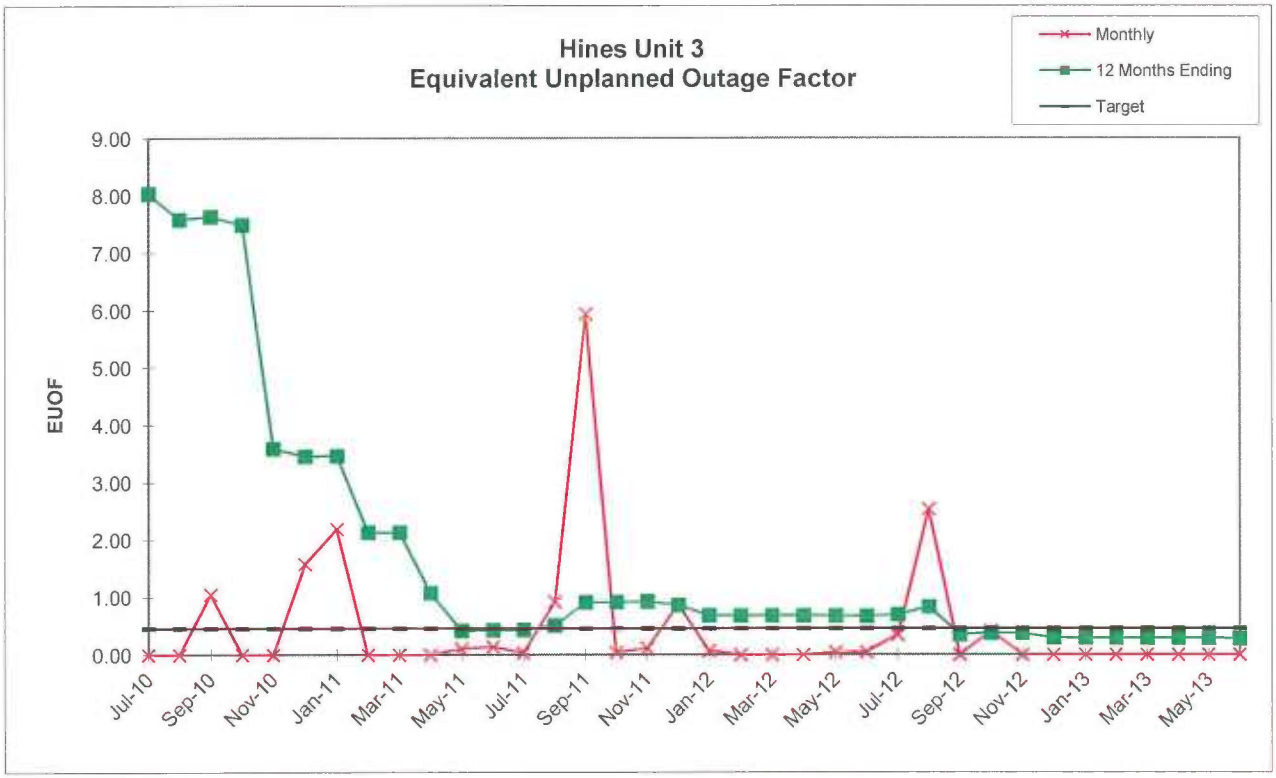
May-13


Hines Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Hines
Unit 4

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	683.93	744.00	681.43	744.00	456.50	609.85	744.00	672.00	333.63	720.00	744.00	720.00	744.00	744.00	720.00	454.48	198.77	550.94
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	183.38
UH	60.07	0.00	38.57	0.00	264.50	134.15	0.00	0.00	409.37	0.00	0.00	0.00	0.00	0.00	0.00	289.52	522.23	9.68
POH	0.00	0.00	0.00	0.00	264.50	122.50	0.00	0.00	409.37	0.00	0.00	0.00	0.00	0.00	0.00	289.52	463.50	0.00
FOH	60.07	0.00	38.57	0.00	0.00	11.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.73	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.68
PFOH	0.00	0.00	88.42	17.00	8.92	0.75	0.00	0.00	4.63	42.67	58.70	3.60	1.67	3.80	0.00	0.00	5.65	0.00
LRPF	0.00	0.00	247.51	232.00	221.92	122.00	0.00	0.00	212.15	206.98	212.00	227.00	144.71	145.00	0.00	0.00	69.00	0.00
EFOH	0.00	0.00	46.37	8.36	4.19	0.19	0.00	0.00	2.08	18.71	26.37	1.73	0.51	1.17	0.00	0.00	0.83	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.55	2.58	6.49	1.82	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	227.23	145.19	144.85	144.74	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.41	0.79	1.99	0.56	0.00	0.00	0.00
NPC	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00

MONTHLY	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	8.07	0.00	5.36	0.00	0.00	1.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.81	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.73
PFOR	0.00	0.00	6.80	1.12	0.92	0.03	0.00	0.00	0.62	2.60	3.54	0.24	0.07	0.16	0.00	0.00	0.42	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.92	0.11	0.27	0.08	0.00	0.00	0.00
EUOR	8.07	0.00	11.80	1.12	0.92	1.91	0.00	0.00	0.62	2.60	3.54	5.16	0.18	0.42	0.08	0.00	23.13	1.73
EUOF	8.07	0.00	11.80	1.12	0.58	1.59	0.00	0.00	0.28	2.60	3.54	5.16	0.18	0.42	0.08	0.00	8.26	1.30
POF	0.00	0.00	0.00	0.00	36.69	16.47	0.00	0.00	55.10	0.00	0.00	0.00	0.00	0.00	0.00	38.91	64.29	0.00
EAF	91.93	100.00	88.20	98.88	62.73	81.94	100.00	100.00	44.62	97.40	96.46	94.84	99.82	99.58	99.92	61.09	27.45	98.70

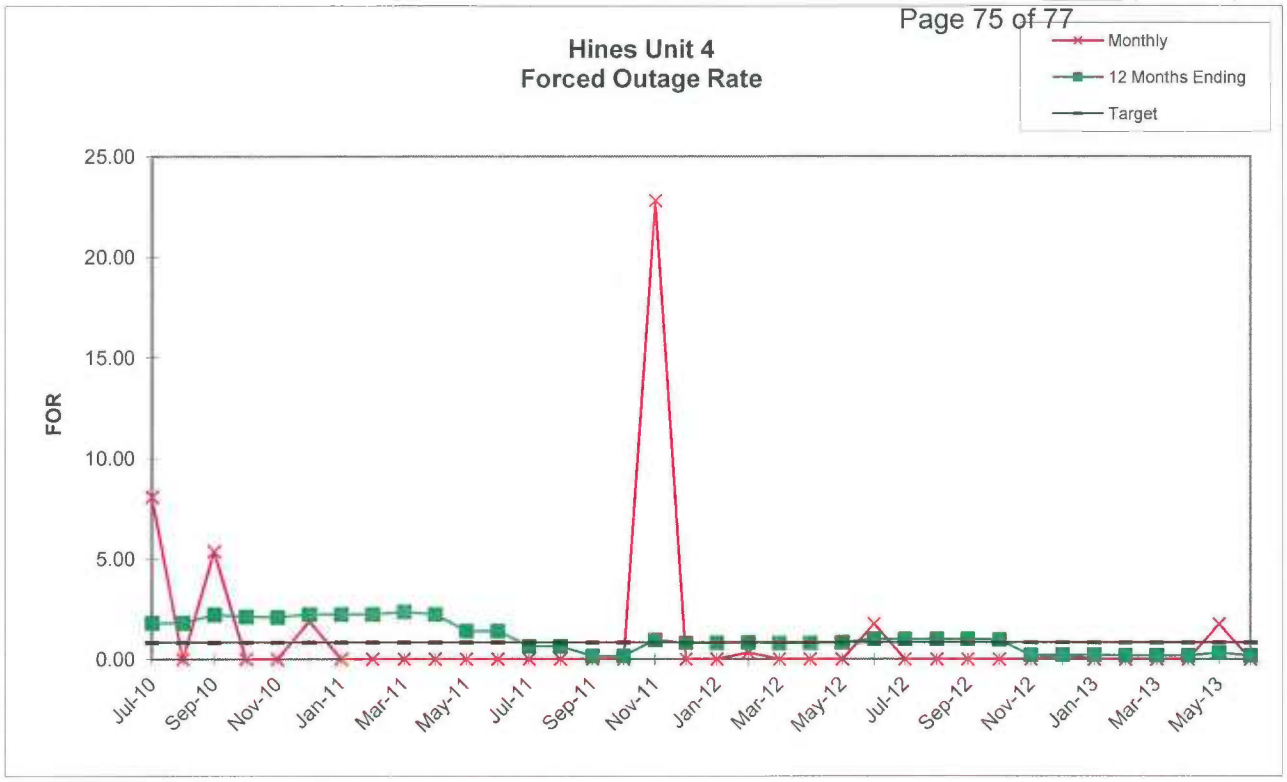
12 MONTHS	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
FOR	1.80	1.80	2.21	2.11	2.08	2.22	2.22	2.22	2.34	2.22	1.38	1.38	0.63	0.63	0.15	0.15	0.94	0.79
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13
PFOR	0.57	0.57	1.16	1.21	1.30	1.30	1.30	1.30	1.27	1.44	1.35	1.38	1.37	1.39	0.80	0.72	0.70	0.70
PMOR	5.14	5.14	5.16	3.14	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.45	0.46	0.48	0.49	0.51	0.52	0.53
EUOR	7.41	7.41	8.40	6.36	3.37	3.50	3.50	3.50	3.58	3.63	2.72	3.19	2.45	2.49	1.43	1.37	2.15	2.14
EUOF	6.74	6.74	7.64	6.06	3.11	3.18	3.18	3.18	3.09	3.30	2.47	2.90	2.23	2.26	1.30	1.20	1.83	1.81
POF	9.06	9.06	9.06	4.76	7.78	9.18	9.18	9.18	13.85	9.09	9.09	9.09	9.09	9.09	9.09	12.40	14.67	13.27
EAF	84.21	84.21	83.31	89.18	89.11	87.64	87.64	87.64	83.06	87.61	88.44	88.01	88.68	88.65	89.61	86.40	83.50	84.92

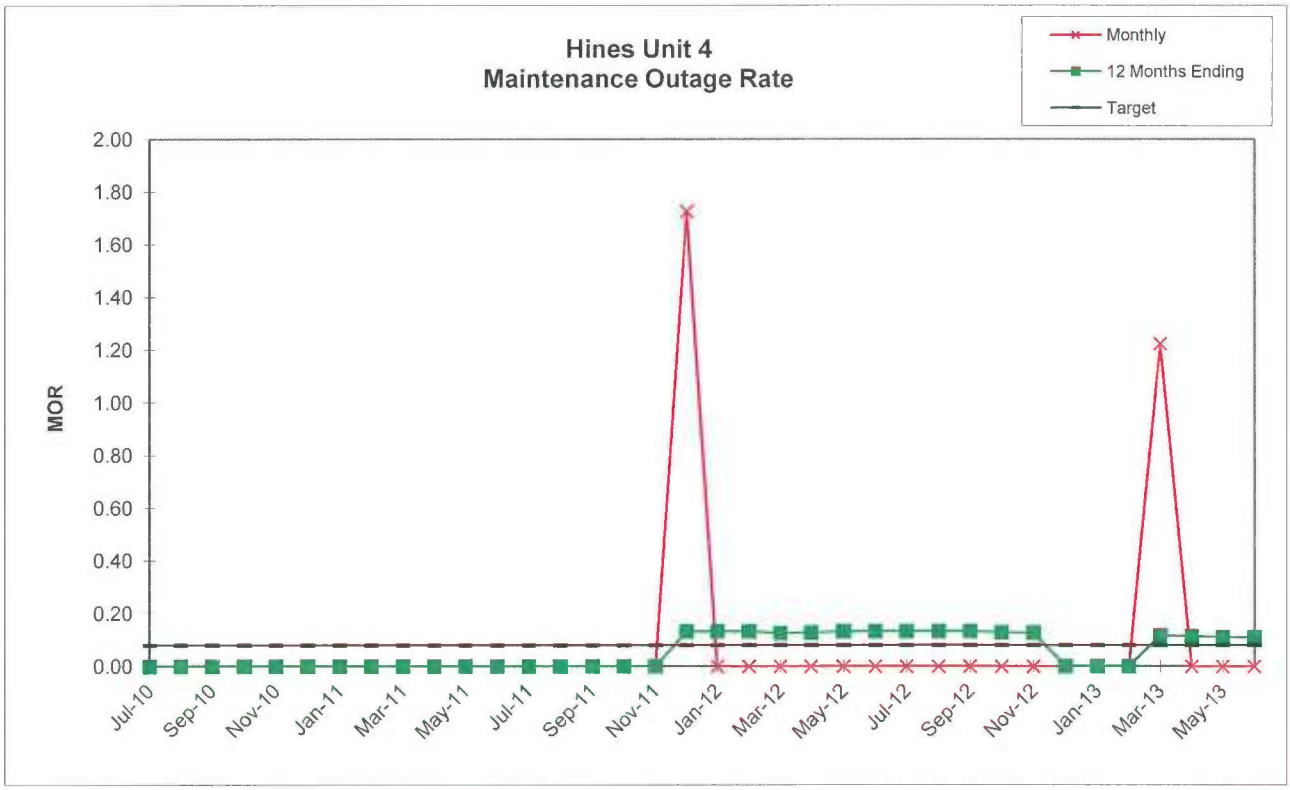
Hines
Unit 4

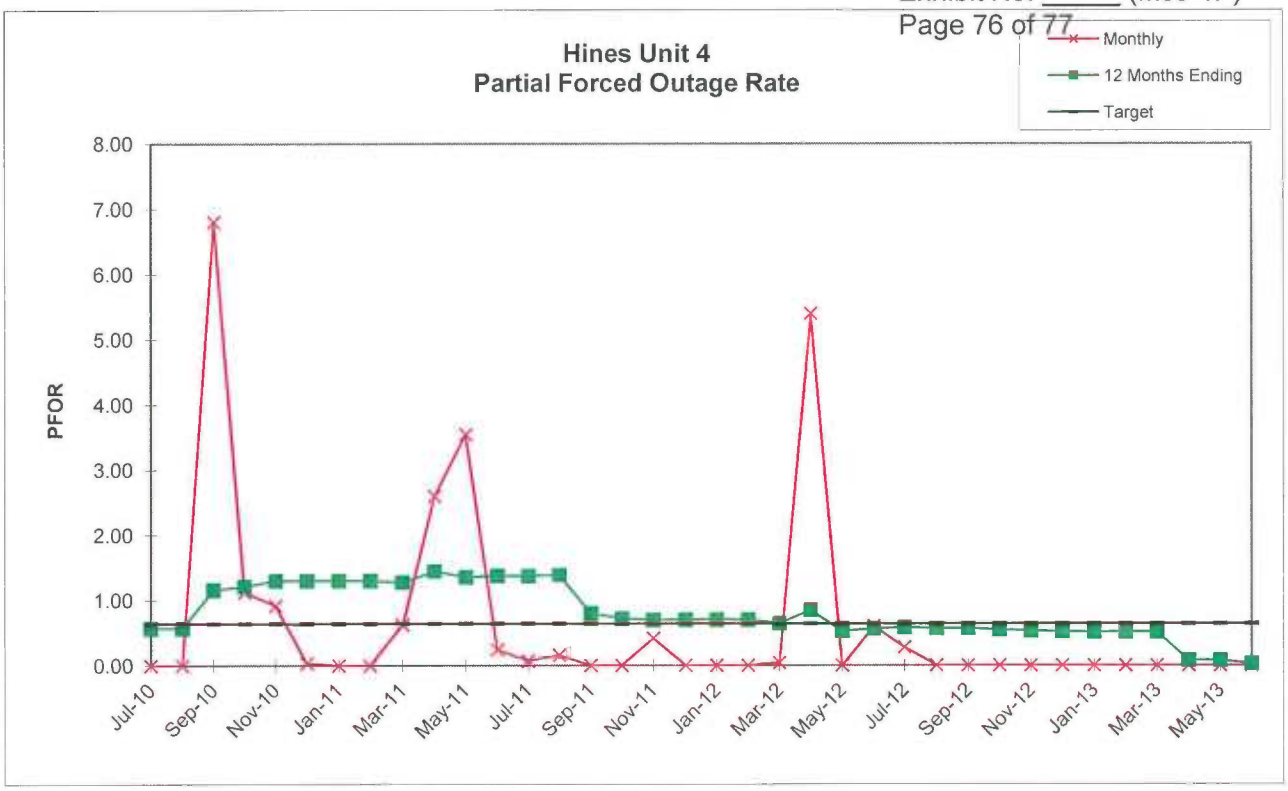
	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
PER HOURS	744.00	696.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00
SER HOURS	712.55	689.40	743.00	625.48	429.43	687.59	744.00	744.00	720.00	744.00	261.93	742.47	744.00	672.00	733.90	720.00	730.98	720.00
RSH	31.45	4.35	0.00	0.00	0.00	20.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	2.25	0.00	94.52	314.57	12.28	0.00	0.00	0.00	0.00	459.07	1.53	0.00	0.00	9.10	0.00	13.02	0.00
POH	0.00	0.00	0.00	94.52	314.57	0.00	0.00	0.00	0.00	0.00	459.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	2.25	0.00	0.00	0.00	12.28	0.00	0.00	0.00	0.00	0.00	1.53	0.00	0.00	0.00	0.00	13.02	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.10	0.00	0.00	0.00
PFOH	0.00	0.00	0.62	51.90	0.00	6.13	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	226.77	307.00	0.00	318.17	362.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.30	33.76	0.00	4.13	2.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	2.50	0.00	11.61	6.70	0.00	7.28	2.21	0.00	1.27	3.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.22
LRPM	145.00	0.00	196.80	208.00	0.00	193.60	140.42	0.00	139.63	140.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	139.79
EMOH	0.77	0.00	4.84	2.95	0.00	2.99	0.66	0.00	0.38	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.66
NPC	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00

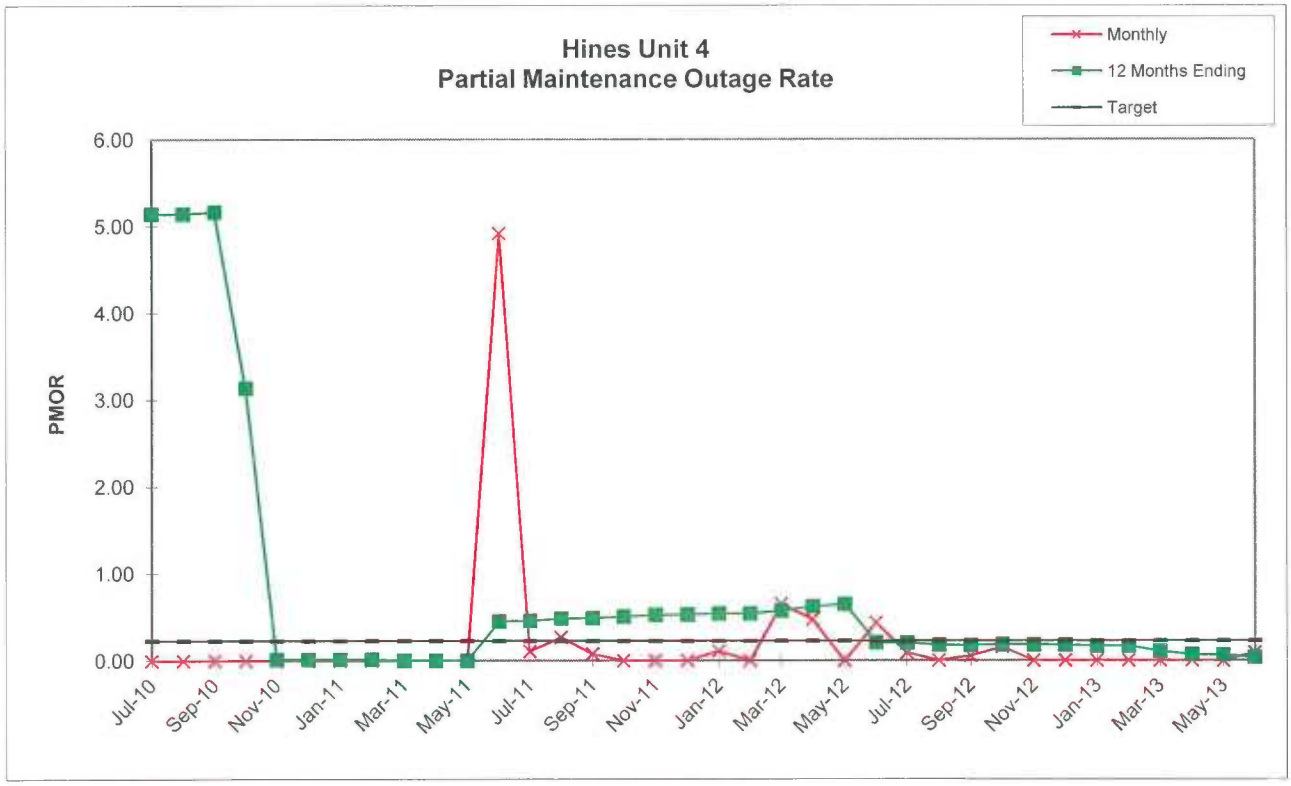
MONTHLY	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.00	0.33	0.00	0.00	0.00	1.75	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	1.75	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.22	0.00	0.00	0.00
PFOR	0.00	0.00	0.04	5.40	0.00	0.60	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.11	0.00	0.65	0.47	0.00	0.43	0.09	0.00	0.05	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
EUOR	0.11	0.33	0.69	5.87	0.00	2.77	0.36	0.00	0.05	0.15	0.00	0.21	0.00	0.00	1.22	0.00	1.75	0.09
EUOF	0.10	0.32	0.69	5.10	0.00	2.69	0.36	0.00	0.05	0.15	0.00	0.21	0.00	0.00	1.22	0.00	1.75	0.09
POF	0.00	0.00	0.00	13.13	42.28	0.00	0.00	0.00	0.00	0.00	63.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.90	99.68	99.31	81.77	57.72	97.31	99.64	100.00	99.95	99.85	36.33	99.79	100.00	100.00	98.78	100.00	98.25	99.91

12 MONTHS	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FOR	0.80	0.82	0.78	0.79	0.82	0.99	0.99	0.99	0.99	0.96	0.19	0.20	0.20	0.18	0.18	0.17	0.32	0.18
MOR	0.13	0.13	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00	0.12	0.11	0.11	0.11
PFOR	0.70	0.70	0.64	0.85	0.52	0.56	0.58	0.56	0.56	0.54	0.53	0.51	0.51	0.51	0.51	0.08	0.07	0.02
PMOR	0.54	0.54	0.57	0.62	0.65	0.20	0.20	0.17	0.17	0.18	0.18	0.17	0.16	0.16	0.10	0.06	0.06	0.03
EUOR	2.16	2.18	2.11	2.37	2.11	1.88	1.90	1.85	1.85	1.79	1.02	0.89	0.88	0.85	0.90	0.43	0.57	0.34
EUOF	1.82	1.84	1.87	2.08	1.78	1.58	1.59	1.56	1.55	1.57	0.89	0.80	0.79	0.76	0.81	0.39	0.54	0.33
POF	13.27	13.23	8.57	9.65	13.23	13.23	13.23	13.23	13.23	9.93	9.88	9.88	9.88	9.91	9.91	8.83	5.24	5.24
EAF	84.91	84.93	89.55	88.27	84.99	85.19	85.18	85.21	85.22	88.50	89.23	89.32	89.33	89.32	89.28	90.78	94.22	94.43


Hines Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
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Jul-12
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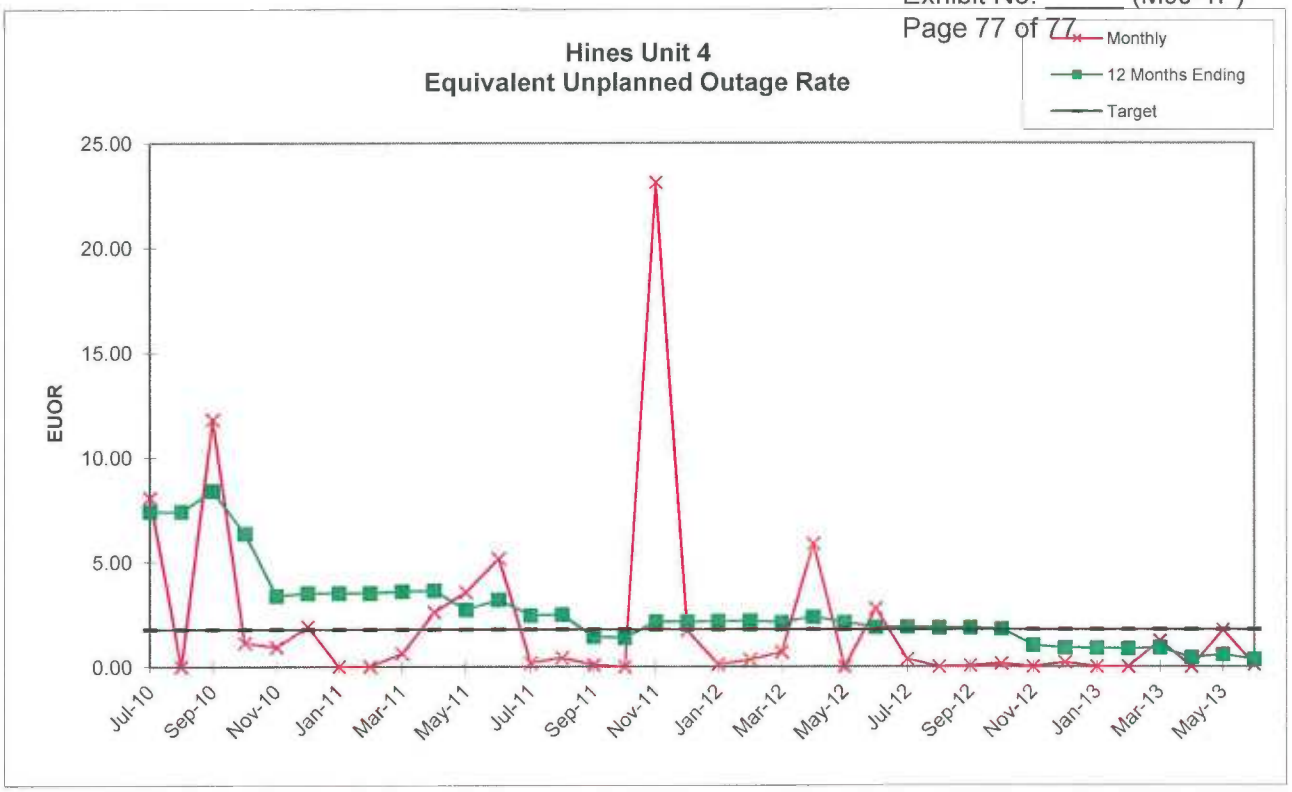
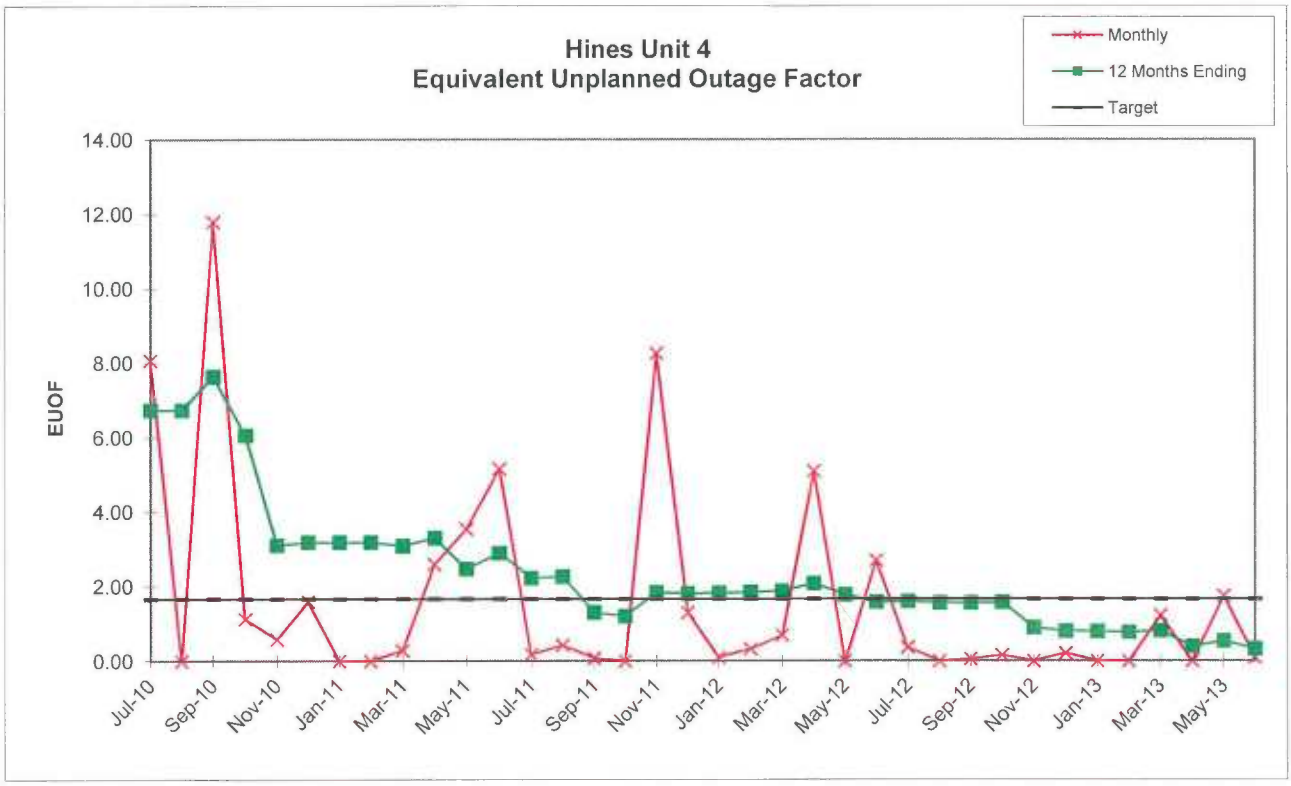
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13


Hines Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-10
Sep-10
Nov-10
Jan-11
Mar-11
May-11
Jul-11
Sep-11
Nov-11
Jan-12
Mar-12
May-12
Jul-12
Sep-12
Nov-12
Jan-13
Mar-13
May-13

Schedule A

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2012 THROUGH DECEMBER 2012
Revised 4/19/2013

NORTHWEST FLORIDA DIVISION			
1	JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	$	31,752,504
2	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD		28,881,063
3	ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD		(2,871,441)
4	ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)		1,567,788
5	INTEREST		(2,435)
6	TRUE-UP COLLECTED		(1,567,788)
7	PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/12)		277,583
8	ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)		(2,596,293)
9	PROJECTED UNDER-RECOVERY PER PROJECTION RE-FILED 10/31/12		(1,477,604)
10	**FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)**		**(1,118,689)**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 31
PARTY Florida Public Utilities Co. (FPUC) (Direct)
DESCRIPTION Curtis Young - CDY-1 (Composite)

Exhibit No.
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY - 1)

Schedule B

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2012 THROUGH DECEMBER 2012
Revised 4/19/2013

NORTHEAST FLORIDA DIVISION		
1 JURISDICTIONAL FUEL COSTS (NET OF GSLD1 / STAND BY FUEL COSTS)	$	29,786,712
2 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD (NET OF GSLD1 /STANDBY FUEL REVENUES)		28,319,913
3 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD		(1,466,799)
4 ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)		3,149,022
5 INTEREST		2,522
6 TRUE-UP COLLECTED		(3,149,022)
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/12)		3,509,614
8 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)		2,045,337
9 PROJECTED UNDER-RECOVERY PER PROJECTION RE-FILED 10/31/12		258,666
10 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)		**1,786,671**

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY - 1)

FLORIDA PUBLIC UTILITIES COMPANY **Schedule M1**

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION

ESTIMATED FOR THE PERIOD: JANUARY 2012 - DECEMBER 2012 Revised 4/19/2013

BASED ON TWELVE MONTHS ACTUAL

NORTHWEST FLORIDA DIVISION

	ACTUAL JANUARY 2012	ACTUAL FEBRUARY 2012	ACTUAL MARCH 2012	ACTUAL APRIL 2012	ACTUAL MAY 2012	ACTUAL JUNE 2012	ACTUAL JULY 2012	ACTUAL AUGUST 2012	ACTUAL SEPTEMBER 2012	ACTUAL OCTOBER 2012	ACTUAL NOVEMBER 2012	ACTUAL DECEMBER 2012	Total
Total System Sales - KWH	24,570,022	20,870,527	21,438,280	20,821,645	21,734,442	25,872,164	28,729,777	30,307,056	30,867,225	27,192,471	24,509,759	23,125,039	300,038,407
Total System Purchases - KWH	25,334,508	22,472,613	23,052,445	22,576,393	27,942,808	28,825,730	32,608,586	30,857,455	27,295,395	24,266,224	23,178,568	25,693,660	314,104,385
System Billing Demand - KW	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	1,175,328
Peak Billing Demand-KW	60,722	59,442	58,004	58,567	58,634	59,278	59,197	58,806	58,866	58,545	58,346	58,284	706,691
Purchased Power Rates:													
Energy/Environmental - $/KWH Loss Factc 0.974	0.06078	0.06078	0.06078	0.06078	0.06078	0.06078	0.05328	0.05328	0.05328	0.05328	0.05328	0.05328	
Demand and Non-Fuel:													
Capacity Charge - $/KWH	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	9.00000	
Transmission and Interconnection - $/KWH	2.43707	2.43707	2.43707	2.43707	2.43707	2.43707	2.35199	2.35199	2.35199	2.35199	2.35199	2.35199	
Distribution Charge	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
Purchased Power Costs:													
Base Fuel Costs	1,580,936	1,402,346	1,438,529	1,408,823	1,743,700	1,798,797	1,783,763	1,687,972	1,493,120	1,327,417	1,267,920	1,405,501	18,338,824
Subtotal Fuel Costs	1,580,936	1,402,346	1,438,529	1,408,823	1,743,700	1,798,797	1,783,763	1,687,972	1,493,120	1,327,417	1,267,920	1,405,501	18,338,824
Demand and Non-Fuel Costs:													
Capacity Charge	881,496	881,496	881,496	881,496	1,637,541	881,496	881,496	881,496	881,496	881,496	881,496	881,496	11,333,997
Transmission and Interconection	147,984	144,864	141,360	142,732	142,895	144,465	(37,062)	138,311	138,452	137,697	137,229	137,083	1,516,010
Distribution Facilities Charge (incl. FERC I/t chrg)	41,636	41,649	36,702	41,476	41,836	41,845	41,912	42,198	42,066	41,797	41,396	41,322	495,835
Meter Reading and Processing Charge	775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs	1,071,891	1,068,784	1,060,333	1,066,479	1,823,047	1,068,581	887,121	1,062,780	1,062,789	1,061,765	1,060,896	1,060,676	13,355,142
Total System Purchased Power Costs	2,652,827	2,471,130	2,498,862	2,475,302	3,566,747	2,867,378	2,670,884	2,750,752	2,555,909	2,389,182	2,328,816	2,466,177	31,693,966
Special Costs	375	12,039	(1,967)	6,201	14,906	9,630	8,513	11,587	(11,240)	8,674	1,661	(1,841)	58,538
Total Costs and Charges	2,653,202	2,483,169	2,496,895	2,481,503	3,581,653	2,877,008	2,679,397	2,762,339	2,544,669	2,397,856	2,330,477	2,464,336	31,752,504
Sales Revenues - Fuel Adjustment Revenues:													
Residential< .10300 .09847	779,890	728,109	698,104	630,001	647,485	732,728	768,712	781,155	782,859	723,618	685,269	706,291	8,664,221
Residential> .11299 .10846	379,913	211,676	171,515	128,238	168,079	333,926	448,345	494,013	504,068	325,140	197,849	245,169	3,607,931
Commercial, Small .10298 .09847	232,599	199,047	199,209	203,666	203,286	244,543	265,531	281,698	289,588	275,033	221,725	201,046	2,816,971
Commercial, Large .09796 .09345	616,059	536,445	585,789	571,303	590,144	711,955	733,912	749,118	798,256	759,560	637,219	546,745	7,836,505
Industrial .09436 .08989	439,728	385,851	425,072	437,153	426,166	432,030	520,961	583,670	573,156	491,446	557,248	475,026	5,747,507
Outside Lighting Private .08049 .07614	25,289	25,559	25,339	24,971	24,462	24,417	24,312	24,728	24,514	25,349	25,263	29,994	304,197
Street Lighting-Public .08072 .07636	7,593	7,891	8,402	8,218	8,098	8,098	8,019	7,942	7,942	7,942	8,021	7,983	96,149
Unbilled Fuel Revenues	(337,464)	96,625	(13,487)	22,007	299,752	12,448	226,796	(157,172)	(152,717)	(232,884)	(85,825)	129,503	(192,418)
Total Fuel Revenues	2,143,607	2,191,203	2,099,943	2,025,557	2,367,472	2,500,145	2,996,588	2,765,152	2,827,666	2,375,204	2,246,769	2,341,757	28,881,063
Non-Fuel Revenues	930,406	842,146	843,308	805,160	829,311	937,210	1,010,586	1,044,212	1,055,681	964,708	892,413	882,148	11,037,289
Total Sales Revenue	3,074,013	3,033,349	2,943,251	2,830,717	3,196,783	3,437,355	4,007,174	3,809,364	3,883,347	3,339,912	3,139,182	3,223,905	39,918,352
KWH Sales:													
Residential< RS	7,571,044	7,068,654	6,853,197	6,308,580	6,574,583	7,440,088	7,805,466	7,934,228	7,949,174	7,347,719	6,958,260	7,172,162	86,983,155
Residential> RS	3,364,093	1,874,589	1,530,566	1,181,586	1,551,177	3,080,852	4,135,795	4,557,052	4,649,542	2,999,755	1,825,744	2,262,264	33,013,015
Commercial, Small GS	2,258,787	1,932,949	1,955,831	2,046,353	2,064,621	2,483,452	2,696,583	2,860,771	2,941,143	2,793,440	2,251,711	2,041,712	28,327,353
Commercial, Large GSD	6,305,451	5,488,146	6,095,240	6,069,594	6,377,443	7,634,371	7,868,968	8,034,731	8,524,715	8,146,984	6,832,766	5,864,633	83,243,042
Industrial GSLD	4,660,008	4,089,048	4,579,376	4,785,056	4,741,224	4,806,464	5,795,844	6,493,500	6,376,532	5,467,476	6,199,552	5,284,804	63,278,884
Outside Lighting-Private OL,OL-2	316,557	319,375	318,508	324,418	319,336	320,879	322,102	322,765	322,110	333,088	336,675	394,918	3,950,731
Street Lighting-Public SL-1, 2, 3	94,082	97,766	105,562	106,058	106,058	106,058	105,019	104,009	104,009	105,051	104,546	1,242,227	
Total KWH Sales	24,570,022	20,870,527	21,438,280	20,821,645	21,734,442	25,872,164	28,729,777	30,307,056	30,867,225	27,192,471	24,509,759	23,125,039	300,038,407
True-up Calculation:													to Date
Fuel Revenues	2,143,607	2,191,203	2,099,943	2,025,557	2,367,472	2,500,145	2,996,588	2,765,152	2,827,666	2,375,204	2,246,769	2,341,757	28,881,063
True-up Provision for the Period - collect/(refund)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(1,567,788)
Gross Receipts Tax Refund	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue	2,274,256	2,321,852	2,230,592	2,156,206	2,498,121	2,630,794	3,127,237	2,895,801	2,958,315	2,505,853	2,377,418	2,472,406	30,448,851
Total Purchased Power Costs	2,653,202	2,483,169	2,496,895	2,481,503	3,581,653	2,877,008	2,679,397	2,762,339	2,544,669	2,397,856	2,330,477	2,464,336	31,752,504
True-up Provision for the Period	(378,946)	(161,317)	(266,303)	(325,297)	(1,083,532)	(246,214)	447,840	133,462	413,646	107,997	46,941	8,070	(1,303,653)
Interest Provision for the Period	1	(33)	(72)	(115)	(206)	(314)	(340)	(299)	(261)	(269)	(284)	(243)	(2,435)
True-up and Interest Provision													
Beginning of Period	277,583	(232,011)	(524,010)	(921,034)	(1,377,095)	(2,591,482)	(2,968,659)	(2,651,808)	(2,649,294)	(2,366,558)	(2,389,479)	(2,473,471)	277,583
True-up Collected or (Refunded)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(1,567,788)
End of Period, Net True-up	(232,011)	(524,010)	(921,034)	(1,377,095)	(2,591,482)	(2,968,659)	(2,651,808)	(2,649,294)	(2,366,558)	(2,389,479)	(2,473,471)	(2,596,293)	(2,596,293)
10% Rule - Interest Provision:													-8.19%
Beginning True-up Amount	277,583	(232,011)	(524,010)	(921,034)	(1,377,095)	(2,591,482)	(2,968,659)	(2,651,808)	(2,649,294)	(2,366,558)	(2,389,479)	(2,473,471)	
Ending True-up Amount Before Interest	(232,012)	(523,977)	(920,962)	(1,376,980)	(2,591,276)	(2,968,345)	(2,651,468)	(2,648,995)	(2,366,297)	(2,389,210)	(2,473,187)	(2,596,050)	
Total Beginning and Ending True-up	45,571	(755,988)	(1,444,971)	(2,298,014)	(3,968,370)	(5,559,826)	(5,620,126)	(5,300,802)	(5,015,590)	(4,755,768)	(4,862,666)	(5,069,522)	
Average True-up Amount	22,785	(377,994)	(722,486)	(1,149,007)	(1,984,185)	(2,779,913)	(2,810,063)	(2,650,401)	(2,507,795)	(2,377,884)	(2,431,333)	(2,534,761)	
Average Annual Interest Rate	0.0750%	0.1050%	0.1200%	0.1200%	0.1250%	0.1350%	0.1450%	0.1350%	0.1250%	0.1350%	0.1400%	0.1150%	
Monthly Average Interest Rate	0.0063%	0.0088%	0.0100%	0.0100%	0.0104%	0.0113%	0.0121%	0.0113%	0.0104%	0.0113%	0.0117%	0.0096%	
Interest Provision	1	(33)	(72)	(115)	(206)	(314)	(340)	(299)	(261)	(269)	(284)	(243)	

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY - 1)
Page 3 of 6

FLORIDA PUBLIC UTILITIES COMPANY Schedule F1

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2012 THROUGH DECEMBER 2012 - Revised 4/19/2013

BASED ON TWELVE MONTHS ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

NORTHEAST FLORIDA DIVISION

			ACTUAL Jan 2012	ACTUAL Feb 2012	ACTUAL Mar 2012	ACTUAL Apr 2012	ACTUAL May 2012	ACTUAL Jun 2012	ACTUAL Jul 2012	ACTUAL Aug 2012	ACTUAL Sep 2012	ACTUAL Oct 2012	ACTUAL Nov 2012	ACTUAL Dec 2012	Total
Total System Sales - KWH			28,029,335	24,186,296	24,498,204	31,175,516	32,448,941	30,630,300	35,829,065	39,158,542	37,120,960	32,692,929	26,022,668	24,157,094	365,949,850
CCA Purchases - KWH			489,271	428,892	134,505	362,260	205,161	367,364	553,362	219,919	546,152	183,399	396,030	761,194	4,647,529
Rayonier Purchases - KWH - On Peak												381,523	102,717	414,016	898,256
Rayonier Purchases - KWH - Off Peak												848,296	223,220	818,735	1,890,251
JEA Purchases - KWH			28,842,412	25,087,950	27,190,792	33,187,225	37,579,747	33,687,433	42,363,666	37,146,721	34,504,861	26,038,990	23,339,180	24,635,480	373,604,457
System Billing Demand - KW			84,986	84,986	53,626	80,864	97,216	95,065	82,432	75,802	73,741	64,333	54,790	61,779	909,620
DEMAND-KW-(network load)			106,810	108,204	77,982	83,186	91,426	111,579	105,266	103,091	94,056	87,374	81,852	91,876	1,142,702
Purchased Power Rates															
CCA Fuel Costs - $/KWH			0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04426	0.04426	0.04426	0.04426	0.04426	
Rayonier -Energy Charge- On Peak												0.04563	0.04563	0.04563	
Rayonier- Energy Charge - Off Peak												0.05822	0.04563	0.05822	
Base Fuel Costs - $/KWH			0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04360	0.04360	0.04360	0.04360	0.04360	
Energy Charge - $/KWH			0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01643	0.01643	0.01643	
Demand and Non-Fuel:															
Demand Charge - $/KW			11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	
Distribution Facilities Charge - $			39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	
Transmission Charge $/KW			1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	
Purchased Power Costs:	CCA Fuel Costs		23,607	20,789	6,519	17,560	9,944	18,230	26,821	7,352	24,123	8,117	17,528	33,690	214,280
	Rayonier Standby Costs		0	0	0	0	0	0	0	0	0	66,797	14,873	66,559	148,229
	JEA Base Fuel Costs		1,372,050	1,197,699	1,298,088	1,584,358	1,794,057	1,608,238	2,022,441	1,440,318	1,499,431	1,135,300	1,017,588	1,079,088	17,048,656
	JEA Fuel Adjustment		464,645	403,414	437,228	533,651	604,282	541,694	681,208	597,319	554,838	429,030	382,855	404,761	6,034,925
	Subtotal Fuel Costs		1,860,303	1,621,902	1,741,835	2,135,569	2,408,283	2,168,162	2,730,470	2,044,989	2,078,392	1,639,244	1,432,844	1,584,098	23,446,091
Demand and Non-Fuel Costs:	Demand Charge		967,140	967,141	610,264	920,232	1,106,319	1,081,840	938,076	862,627	839,173	732,110	623,510	703,045	10,351,477
	Distribution Facilities Charge		39,736	39,736	39,736	39,736	39,737	39,736	39,736	39,737	39,736	39,736	39,736	39,736	476,834
	Transmission Charge		161,282	163,388	117,753	125,611	138,053	168,484	158,951	155,668	142,025	131,935	121,048	138,733	1,722,931
Subtotal Demand & Non-Fuel Costs			1,168,158	1,170,265	767,753	1,085,579	1,284,109	1,290,060	1,136,763	1,058,032	1,020,934	903,781	784,294	881,514	12,551,242
Total System Purchased Power Costs			3,028,461	2,792,167	2,509,588	3,221,148	3,692,392	3,458,222	3,867,233	3,103,021	3,099,326	2,543,025	2,217,138	2,465,612	35,997,333
Less Direct Billing To GSLD1 Class:	Demand		174,432	190,339	196,774	444,521	498,334	497,596	114,008	144,320	207,229	216	284,474	126,128	2,878,371
	Commodity		312,259	260,839	290,184	641,958	638,048	263,562	279,824	307,686	253,623	0	146,968	182,948	3,577,899
Net Purchased Power Costs			2,541,770	2,340,989	2,022,630	2,134,669	2,556,010	2,697,064	3,473,401	2,651,015	2,638,474	2,542,809	1,785,696	2,156,536	29,541,063
	Special Costs		21,227	42,405	10,133	20,380	45,068	39,415	15,769	15,290	13,969	9,788	13,315	3,028	249,787
Total Costs and Charges			2,562,997	2,383,394	2,032,763	2,155,049	2,601,078	2,736,479	3,489,170	2,666,305	2,652,443	2,552,597	1,799,011	2,159,564	29,790,850
Sales Revenues - Fuel Adjustment Revenues:															
RS< 1,000 kwh	.09304		879,477	832,934	825,357	829,445	867,932	963,995	1,061,003	1,088,905	1,051,020	997,274	862,744	844,802	11,104,888
RS> 1,000 kwh	.10304		391,757	246,544	215,492	237,682	310,711	481,227	777,490	876,203	776,399	614,740	303,577	290,852	5,522,674
GS	.08824		164,216	154,706	157,573	178,324	188,357	213,162	247,431	271,249	268,528	263,953	227,411	184,319	2,519,229
GSD	08730		535,728	454,266	483,348	525,725	534,396	599,531	657,404	683,097	705,638	668,024	537,081	444,328	6,828,566
GSLD	08747		158,914	151,075	140,117	169,026	169,833	186,113	182,673	223,401	221,429	236,863	209,566	164,947	2,213,957
OL	.06265		7,308	7,217	7,223	7,232	6,447	7,161	6,108	7,117	7,073	7,319	7,111	7,083	84,399
SL,CSL	.06247		4,485	4,492	4,493	4,554	4,493	4,493	4,493	4,493	4,493	235	9,885	4,493	55,102
Unbilled Fuel Revenues			82,372	(456,952)	432,170	(200,017)	461,057	(123,860)	648,834	(609,697)	297,757	(588,874)	66,690	(18,381)	(8,902)
Total Fuel Revenues (Excl. GSLD1)			2,224,257	1,394,282	2,265,773	1,751,971	2,543,226	2,331,822	3,585,436	2,544,768	3,332,337	2,199,534	2,224,065	1,922,443	28,319,913
GSLD1 Fuel Reven	.00000		486,691	451,178	486,958	1,086,479	1,136,382	761,158	393,832	452,006	460,852	216	431,442	309,076	6,456,270
Non-Fuel Revenues			892,148	825,870	824,625	919,607	956,465	1,010,736	1,080,528	1,140,090	1,099,466	991,327	925,547	843,333	11,509,743
Total Sales Revenue			3,603,096	2,671,330	3,577,356	3,758,057	4,636,073	4,103,716	5,059,796	4,136,864	4,892,655	3,191,077	3,581,054	3,074,852	46,285,926
KWH Sales:	RS< 1,000 kwh		9,453,273	8,952,137	8,873,585	8,914,647	9,328,285	10,360,746	11,403,741	11,705,348	11,296,443	10,718,779	9,272,838	9,083,630	119,363,452
	RS> 1,000 kwh		3,802,170	2,392,797	2,092,597	2,306,781	3,015,569	4,670,475	7,545,490	8,503,893	7,541,624	5,971,947	2,954,176	2,822,828	53,620,347
	GS		1,862,938	1,753,309	1,786,017	2,020,972	2,134,684	2,397,303	2,804,183	3,074,118	3,043,274	2,991,256	2,575,585	2,089,028	28,532,667
	GSD		6,135,871	5,203,682	5,536,813	6,022,257	6,121,578	6,867,713	7,530,640	7,824,964	8,083,177	7,652,301	6,152,323	5,089,836	78,221,155
	GSLD		1,816,840	1,727,220	1,601,940	1,932,460	1,941,680	2,127,800	2,088,480	2,554,120	2,531,580	2,708,020	2,395,940	1,885,820	25,311,900
	GSLD1		4,770,000	3,970,000	4,420,000	9,790,000	9,720,000	4,020,000	4,270,000	5,310,000	4,440,000	2,530,000	2,400,000	3,000,000	58,640,000
	OL		116,450	115,250	115,336	115,500	115,229	114,347	114,615	114,183	112,946	116,866	113,559	114,036	1,378,317
	SL,CSL		71,793	71,901	71,916	72,899	71,916	71,916	71,916	71,916	71,916	3,760	158,247	71,916	882,012
Total KWH Sales			28,029,335	24,186,296	24,498,204	31,175,516	32,448,941	30,630,300	35,829,065	39,158,542	37,120,960	32,692,929	26,022,668	24,157,094	365,949,850
True-up Calculation (Excl. GSLD1):															
Fuel Revenues			2,224,257	1,394,282	2,265,773	1,751,971	2,543,226	2,331,822	3,585,436	2,544,768	3,332,337	2,199,534	2,224,065	1,922,443	28,319,913
True-up Provision - collect/(refund)			(262,424)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(3,149,022)
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0				0
Fuel Revenue			2,486,681	1,656,700	2,528,191	2,014,389	2,805,644	2,594,240	3,847,854	2,807,186	3,594,755	2,461,952	2,486,483	2,184,861	31,468,935
Net Purchased Power and Other Fuel Costs			2,562,997	2,383,394	2,032,763	2,155,049	2,601,078	2,736,479	3,489,170	2,666,305	2,652,443	2,552,597	1,799,011	2,159,564	29,790,850
True-up Provision for the Period			(76,316)	(726,694)	495,428	(140,660)	204,566	(142,239)	358,684	140,881	942,312	(90,645)	687,472	25,297	1,678,086
Interest Provision for the Period			211	236	230	222	207	198	194	180	194	230	242	208	2,552
Beginning of Period True-up and Interest Provision			3,512,494	3,173,965	2,185,089	2,418,329	2,015,473	1,957,828	1,553,369	1,649,829	1,528,472	2,208,559	1,855,726	2,281,022	3,512,494
True-up Collected or (Refunded)			(262,424)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(3,149,022)
End of Period, Net True-up and Int. Prov.			3,173,965	2,185,089	2,418,329	2,015,473	1,957,828	1,553,369	1,649,829	1,528,472	2,208,559	1,855,726	2,281,022	2,044,109	2,044,109
Beginning True-up Amount			3,512,494	3,173,965	2,185,089	2,418,329	2,015,473	1,957,828	1,553,369	1,649,829	1,528,472	2,208,559	1,855,726	2,281,022	
Ending True-up Amount Before Interest			3,173,754	2,184,853	2,418,099	2,015,251	1,957,621	1,553,171	1,649,635	1,528,292	2,208,365	1,855,496	2,280,780	2,043,902	
Total Beginning and Ending True-up			6,686,248	5,358,818	4,603,188	4,433,580	3,973,094	3,510,999	3,203,004	3,178,121	3,736,837	4,064,056	4,136,507	4,324,924	
Average True-up Amount			3,343,124	2,679,409	2,301,594	2,216,790	1,986,547	1,755,499	1,601,502	1,589,060	1,868,419	2,032,028	2,068,253	2,162,462	
Average Annual Interest Rate			0.0750%	0.1050%	0.1200%	0.1200%	0.1250%	0.1350%	0.1450%	0.1350%	0.1250%	0.1350%	0.1400%	0.1150%	
Interest Provision			211	236	230	222	207	198	194	180	194	230	242	208	

10% Rule Interest Provision:
5.68%

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY - 1)
Page 4 of 6

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E1-B

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION - **without Gulf Power Amendment 1**

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2012 - DECEMBER 2012 - Revised 4/19/2013

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

NORTHWEST FLORIDA DIVISION

			ACTUAL JANUARY 2012	ACTUAL FEBRUARY 2012	ACTUAL MARCH 2012	ACTUAL APRIL 2012	ACTUAL MAY 2012	ACTUAL JUNE 2012	Estimated JULY 2012	Estimated AUGUST 2012	Estimated SEPTEMBER 2012	Estimated OCTOBER 2012	Estimated NOVEMBER 2012	Estimated DECEMBER 2012	Total
Total System Sales - KWH			24,570,022	20,870,527	21,438,280	20,821,645	21,734,442	25,872,164	31,577,000	32,181,000	30,842,000	28,381,000	23,568,000	25,861,000	307,717,080
Total System Purchases - KWH			25,334,508	22,472,613	23,052,445	22,576,393	27,942,808	28,825,730	31,333,192	31,264,804	29,804,083	27,212,825	22,630,754	24,992,271	317,442,426
System Billing Demand - KW			97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	97,944	1,175,328
Peak Billing Demand-KW			60,722	59,442	58,004	58,567	58,634	59,278	60,900	60,900	60,900	60,900	60,900	60,900	720,047
Purchased Power Rates:															
Energy/Environmental - $/KWH	Loss Factor	0.974	0.06078	0.06078	0.06078	0.06078	0.06078	0.06078	0.05328	0.05328	0.05328	0.05328	0.05328	0.05328	
Demand and Non-Fuel:															
Capacity Charge - $/KWH			9.00000	9.000000	9.000000	9.000000	9.000000	9.000000	9.000000	9.000000	9.000000	9.000000	9.000000	9.000000	
Transmission and Interconnection - $/KWH			2.43707	2.43707	2.43707	2.43707	2.43707	2.43707	2.35199	2.35199	2.35199	2.35199	2.35199	2.35199	
Distribution Charge			39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
Purchased Power Costs:															
Base Fuel Costs			1,580,936	1,402,346	1,438,529	1,408,823	1,743,700	1,798,797	1,713,996	1,710,255	1,630,351	1,488,603	1,237,953	1,367,134	18,521,423
Subtotal Fuel Costs			1,580,936	1,402,346	1,438,529	1,408,823	1,743,700	1,798,797	1,713,996	1,710,255	1,630,351	1,488,603	1,237,953	1,367,134	18,521,423
Demand and Non-Fuel Costs:															
Capacity Charge			881,496	881,496	881,496	881,496	1,637,541	881,496	881,496	881,496	881,496	881,496	881,496	881,496	11,333,997
Transmission and Interconection			147,984	144,864	141,360	142,732	142,895	144,465	(33,058)	143,236	143,236	143,236	143,236	143,236	1,547,422
Distribution Facilities Charge (incl. FERC I/t chrg)			41,636	41,649	36,702	41,476	41,836	41,845	42,549	42,544	42,420	42,202	41,773	41,972	498,604
Meter Reading and Processing Charge			775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs			1,071,891	1,068,784	1,060,333	1,066,479	1,823,047	1,068,581	891,762	1,068,051	1,067,927	1,067,709	1,067,280	1,067,479	13,389,323
Total System Purchased Power Costs			2,652,827	2,471,130	2,498,862	2,475,302	3,566,747	2,867,378	2,605,758	2,778,306	2,698,278	2,556,312	2,305,233	2,434,613	31,910,746
Special Costs			375	12,039	(1,967)	9,751	14,906	9,630	6,000	6,000	6,000	6,000	6,000	6,000	80,734
Total Costs and Charges			2,653,202	2,483,169	2,496,895	2,485,053	3,581,653	2,877,008	2,611,758	2,784,306	2,704,278	2,562,312	2,311,233	2,440,613	31,991,480
Sales Revenues - Fuel Adjustment Revenues:															
Residential<	0.10300	0.09847	779,890	728,109	698,104	630,001	647,485	732,728	747,577	809,416	749,251	725,422	582,839	727,194	8,558,016
Residential>	0.11299	0.10846	379,913	211,676	171,515	128,238	168,079	333,926	572,679	682,551	643,179	454,781	361,395	455,865	4,563,797
Commercial, Small	0.10298	0.09847	232,599	199,047	199,209	203,666	203,286	244,543	299,641	282,212	266,457	253,656	204,225	209,148	2,797,689
Commercial, Large	0.09796	0.09345	616,059	536,445	585,789	571,303	590,144	711,955	866,120	828,739	816,683	791,171	652,206	644,450	8,211,064
Industrial	0.09436	0.08989	439,728	385,851	425,072	437,153	426,166	432,030	536,435	495,358	488,796	481,785	435,314	434,236	5,417,924
Outside Lighting Private	0.08049	0.07614	25,289	25,559	25,339	24,971	24,462	24,417	25,201	24,972	24,744	24,744	24,820	24,896	299,414
Street Lighting-Public	0.08072	0.07636	7,593	7,891	8,402	8,218	8,098	8,098	7,254	7,254	7,254	7,177	7,254	7,254	91,747
Unbilled Fuel Revenues			(337,464)	96,625	(13,487)	22,007	299,752	12,448						220,000	299,881
Total Fuel Revenues			2,143,607	2,191,203	2,099,943	2,025,557	2,367,472	2,500,145	3,054,907	3,130,502	2,996,364	2,738,736	2,268,053	2,723,043	30,239,532
Non-Fuel Revenues			930,406	842,146	843,308	805,160	829,311	937,210	1,242,985	1,184,091	1,143,328	1,070,364	948,047	1,014,257	11,790,613
Total Sales Revenue			3,074,013	3,033,349	2,943,251	2,830,717	3,196,783	3,437,355	4,297,892	4,314,593	4,139,692	3,809,100	3,216,100	3,737,300	42,030,145
KWH Sales:															
Residential<	RS		7,571,044	7,068,654	6,853,197	6,308,580	6,574,583	7,440,088	7,592,000	8,220,000	7,609,000	7,367,000	5,919,000	7,385,000	85,908,146
Residential>	RS		3,364,093	1,874,589	1,530,566	1,181,586	1,551,177	3,080,852	5,280,000	6,293,000	5,930,000	4,193,000	3,332,000	4,203,000	41,813,863
Commercial, Small	GS		2,258,787	1,932,949	1,955,831	2,046,353	2,064,621	2,483,452	3,043,000	2,866,000	2,706,000	2,576,000	2,074,000	2,124,000	28,130,993
Commercial, Large	GSD		6,305,451	5,488,146	6,095,240	6,069,594	6,377,443	7,634,371	9,268,000	8,868,000	8,739,000	8,466,000	6,979,000	6,896,000	87,186,245
Industrial	GSLD		4,660,008	4,089,048	4,579,376	4,785,056	4,741,224	4,806,464	5,968,000	5,511,000	5,438,000	5,360,000	4,843,000	4,831,000	59,612,176
Outside Lighting-Private	OL,OL-2		316,557	319,375	318,508	324,418	319,336	320,879	331,000	328,000	325,000	325,000	326,000	327,000	3,881,073
Street Lighting-Public	SL-1, 2, 3		94,082	97,766	105,562	106,058	106,058	106,058	95,000	95,000	95,000	94,000	95,000	95,000	1,184,584
Total KWH Sales			24,570,022	20,870,527	21,438,280	20,821,645	21,734,442	25,872,164	31,577,000	32,181,000	30,842,000	28,381,000	23,568,000	25,861,000	307,717,080
True-up Calculation:															to Date
Fuel Revenues			2,143,607	2,191,203	2,099,943	2,025,557	2,367,472	2,500,145	3,054,907	3,130,502	2,996,364	2,738,736	2,268,053	2,723,043	30,239,532
True-up Provision for the Period - collect/(refund)			(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(1,567,788)
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue			2,274,256	2,321,852	2,230,592	2,156,206	2,498,121	2,630,794	3,185,556	3,261,151	3,127,013	2,869,385	2,398,702	2,853,692	31,807,320
Total Purchased Power Costs			2,653,202	2,483,169	2,496,895	2,485,053	3,581,653	2,877,008	2,611,758	2,784,306	2,704,278	2,562,312	2,311,233	2,440,613	31,991,480
True-up Provision for the Period			(378,946)	(161,317)	(266,303)	(328,847)	(1,083,532)	(246,214)	573,798	476,845	422,735	307,073	87,469	413,079	(184,160)
Interest Provision for the Period			1	(33)	(72)	(115)	(207)	(314)	(641)	(549)	(475)	(420)	(405)	(377)	(3,607)
True-up and Interest Provision															
Beginning of Period			277,951	(231,643)	(523,642)	(920,666)	(1,380,277)	(2,594,665)	(2,971,842)	(2,529,334)	(2,183,687)	(1,892,076)	(1,716,072)	(1,759,657)	277,951
True-up Collected or (Refunded)			(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(130,649)	(1,567,788)
End of Period, Net True-up			(231,643)	(523,642)	(920,666)	(1,380,277)	(2,594,665)	(2,971,842)	(2,529,334)	(2,183,687)	(1,892,076)	(1,716,072)	(1,759,657)	(1,477,604)	(1,477,604)
10% Rule - Interest Provision:															-4.63%
Beginning True-up Amount			277,951	(231,643)	(523,642)	(920,666)	(1,380,277)	(2,594,665)	(2,971,842)	(2,529,334)	(2,183,687)	(1,892,076)	(1,716,072)	(1,759,657)	
Ending True-up Amount Before Interest			(231,644)	(523,609)	(920,594)	(1,380,162)	(2,594,458)	(2,971,528)	(2,528,693)	(2,183,138)	(1,891,601)	(1,715,652)	(1,759,252)	(1,477,227)	
Total Beginning and Ending True-up			46,307	(755,252)	(1,444,235)	(2,300,828)	(3,974,734)	(5,566,192)	(5,500,534)	(4,712,471)	(4,075,287)	(3,607,727)	(3,475,323)	(3,236,883)	
Average True-up Amount			23,153	(377,626)	(722,118)	(1,150,414)	(1,987,367)	(2,783,096)	(2,750,267)	(2,356,236)	(2,037,644)	(1,803,864)	(1,737,662)	(1,618,442)	
Average Annual Interest Rate			0.0750%	0.1050%	0.1200%	0.1200%	0.1250%	0.1350%	0.2800%	0.2800%	0.2800%	0.2800%	0.2800%	0.2800%	
Monthly Average Interest Rate			0.0063%	0.0088%	0.0100%	0.0100%	0.0104%	0.0113%	0.0233%	0.0233%	0.0233%	0.0233%	0.0233%	0.0233%	
Interest Provision			1	(33)	(72)	(115)	(207)	(314)	(641)	(549)	(475)	(420)	(405)	(377)	

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY - 1)
Page 5 of 6

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E-1b

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2012 THROUGH DECEMBER 2012 - Revised 4/19/2013

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

NORTHEAST FLORIDA DIVISION

		ACTUAL Jan 2012	ACTUAL Feb 2012	ACTUAL Mar 2012	ACTUAL Apr 2012	ACTUAL May 2012	ACTUAL Jun 2012	Estimated Jul 2012	Estimated Aug 2012	Estimated Sep 2012	Estimated Oct 2012	Estimated Nov 2012	Estimated Dec 2012	Total
Total System Sales - KWH		28,029,335	24,186,296	24,498,204	31,175,516	32,448,941	30,630,300	40,344,000	40,168,000	37,668,000	33,068,000	28,386,000	28,456,000	379,058,592
CCA Purchases - KWH		489,271	428,892	134,505	362,280	205,161	367,364	600,000	600,000	600,000	600,000	600,000	600,000	5,587,473
JEA Purchases - KWH		28,842,412	25,087,950	27,190,792	33,187,225	37,579,747	33,687,433	43,274,325	42,678,153	38,898,388	36,415,990	28,694,485	29,508,540	405,045,440
System Billing Demand - KW		84,986	84,986	53,626	80,864	97,216	95,065	89,900	88,700	87,600	78,700	68,900	76,800	987,343
DEMAND-KW-(network load)		106,810	108,204	77,982	83,186	91,426	111,579	115,072	113,536	112,128	100,736	88,192	98,304	1,207,155
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	0.04847	
Base Fuel Costs - $/KWH		0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	0.04774	
Energy Charge - $/KWH		0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01608	0.01643	0.01643	0.01643	
Demand and Non-Fuel:														
Demand Charge - $/KW		11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	
Customer Charge - $		39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	
Transmission Charge $/KW		1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	
Purchased Power Costs:	CCA Fuel Costs	23,607	20,789	6,519	17,560	9,944	18,230	29,082	29,082	29,082	29,082	29,082	29,082	271,141
	JEA Base Fuel Costs	1,372,050	1,197,699	1,298,088	1,584,358	1,794,057	1,608,238	2,065,916	2,037,455	1,857,009	1,738,499	1,369,875	1,408,738	19,331,982
	JEA Fuel Adjustment	464,645	403,414	437,228	533,651	604,282	541,694	695,851	686,265	625,486	598,315	471,450	484,825	6,547,106
	Subtotal Fuel Costs	1,860,303	1,621,902	1,741,835	2,135,569	2,408,283	2,168,162	2,790,849	2,752,802	2,511,577	2,365,896	1,870,407	1,922,645	26,150,230
Demand and Non-Fuel Costs:	Demand Charge	967,140	967,141	610,264	920,232	1,106,319	1,081,840	1,023,062	1,009,406	996,888	895,606	784,082	873,984	11,235,964
	Customer Charge	39,736	39,736	39,736	39,736	39,737	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,833
	Transmission Charge	161,282	163,388	117,753	125,611	138,053	168,484	173,759	171,439	169,313	152,111	133,170	148,439	1,822,802
Subtotal Demand & Non-Fuel Costs		1,168,158	1,170,265	767,753	1,085,579	1,284,109	1,290,060	1,236,557	1,220,581	1,205,937	1,087,453	956,988	1,062,159	13,535,599
Total System Purchased Power Costs		3,028,461	2,792,167	2,509,588	3,221,148	3,692,392	3,458,222	4,027,406	3,973,383	3,717,514	3,453,349	2,827,395	2,984,804	39,685,829
Less Direct Billing To GSLD1 Class:	Demand	174,432	190,339	196,774	444,521	498,334	497,596	159,591	159,591	254,511	159,591	159,591	254,511	3,149,382
	Commodity	312,259	260,839	290,184	641,958	638,048	263,562	267,312	351,750	305,921	243,190	302,050	366,953	4,244,025
Net Purchased Power Costs		2,541,770	2,340,989	2,022,630	2,134,669	2,556,010	2,697,064	3,600,503	3,462,042	3,157,082	3,050,568	2,365,754	2,363,340	32,292,421
	Special Costs	21,227	42,405	10,133	16,242	45,068	39,415							174,490
Total Costs and Charges		2,562,997	2,383,394	2,032,763	2,150,911	2,601,078	2,736,479	3,600,503	3,462,042	3,157,082	3,050,568	2,365,754	2,363,340	32,466,911
Sales Revenues - Fuel Adjustment Revenues:														
RS<	.09304	879,477	832,934	825,357	829,445	867,932	963,995	1,333,077	1,264,879	1,168,955	1,009,949	769,441	770,836	11,516,277
RS>	.10304	391,757	246,544	215,492	237,682	310,711	481,227	770,739	731,378	675,839	584,031	444,824	445,751	5,535,975
GS	.08824	164,216	154,706	157,573	178,324	188,357	213,162	267,191	264,191	246,454	238,689	197,128	179,657	2,449,648
GSD	.08730	535,728	454,266	483,348	525,725	534,396	599,531	778,629	754,447	752,177	694,384	590,061	535,673	7,238,365
GSLD	.08747	158,914	151,075	140,117	169,026	169,833	186,113	206,254	204,855	204,330	179,314	184,299	175,027	2,129,157
OL	.06265	7,308	7,217	7,223	7,232	6,447	7,161	7,455	7,393	7,142	7,142	7,330	7,706	86,756
SL,CSL	.06247	4,485	4,492	4,493	4,554	4,493	4,493	5,935	5,872	5,935	5,935	5,872	5,872	62,431
Unbilled Fuel Revenues		82,372	(456,952)	432,170	(200,017)	461,057	(123,860)							194,770
Total Fuel Revenues (Excl. GSLD1)		2,224,257	1,394,282	2,265,773	1,751,971	2,543,226	2,331,822	3,369,280	3,233,015	3,060,832	2,719,444	2,198,955	2,120,522	29,213,379
GSLD1 Fuel Revenues		486,691	451,178	486,958	1,086,479	1,136,382	761,158	426,903	511,341	560,432	402,781	461,641	621,464	7,393,408
Non-Fuel Revenues		892,148	825,870	824,625	919,607	956,465	1,010,736	1,515,217	1,482,544	1,275,736	1,223,975	1,043,304	1,106,314	13,076,542
Total Sales Revenue		3,603,096	2,671,330	3,577,356	3,758,057	4,636,073	4,103,716	5,311,400	5,226,900	4,897,000	4,346,200	3,703,900	3,848,300	49,683,328
KWH Sales:	RS<	9,453,273	8,952,137	8,873,585	8,914,647	9,328,285	10,360,746	14,328,000	13,595,000	12,564,000	10,855,000	8,270,000	8,285,000	123,779,673
	RS>	3,802,170	2,392,797	2,092,597	2,306,781	3,015,569	4,670,475	7,480,000	7,098,000	6,559,000	5,668,000	4,317,000	4,326,000	53,728,389
	GS	1,862,938	1,753,309	1,786,017	2,020,972	2,134,684	2,397,303	3,028,000	2,994,000	2,793,000	2,705,000	2,234,000	2,036,000	27,745,223
	GSD	6,135,871	5,203,682	5,536,813	6,022,257	6,121,578	6,867,713	8,919,000	8,642,000	8,616,000	7,954,000	6,759,000	6,136,000	82,913,914
	GSLD	1,816,840	1,727,220	1,601,940	1,932,460	1,941,680	2,127,800	2,358,000	2,342,000	2,336,000	2,050,000	2,107,000	2,001,000	24,341,940
	GSLD1	4,770,000	3,970,000	4,420,000	9,790,000	9,720,000	4,020,000	4,017,000	5,285,000	4,591,000	3,627,000	4,488,000	5,455,000	64,153,000
	OL	116,450	115,250	115,336	115,500	115,229	114,347	119,000	118,000	114,000	114,000	117,000	123,000	1,397,112
	SL,CSL	71,793	71,901	71,916	72,899	71,916	71,916	95,000	94,000	95,000	95,000	94,000	94,000	999,341
	Total KWH Sales	28,029,335	24,186,296	24,498,204	31,175,516	32,448,941	30,630,300	40,344,000	40,168,000	37,668,000	33,068,000	28,386,000	28,456,000	379,058,592
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		2,224,257	1,394,282	2,265,773	1,751,971	2,543,226	2,331,822	3,369,280	3,233,015	3,060,832	2,719,444	2,198,955	2,120,522	29,213,379
True-up Provision - collect/(refund)		(262,424)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(3,149,022)
Gross Receipts Tax Refund														0
Fuel Revenue		2,486,681	1,656,700	2,528,191	2,014,389	2,805,644	2,594,240	3,631,698	3,495,433	3,323,250	2,981,862	2,461,373	2,382,940	32,362,401
Net Purchased Power and Other Fuel Costs		2,562,997	2,383,394	2,032,763	2,150,911	2,601,078	2,736,479	3,600,503	3,462,042	3,157,082	3,050,568	2,365,754	2,363,340	32,466,911
True-up Provision for the Period		(76,316)	(726,694)	495,428	(136,522)	204,566	(142,239)	31,195	33,391	166,168	(68,706)	95,619	19,600	(104,510)
Interest Provision for the Period		210	236	230	222	207	199	335	282	244	194	136	89	2,584
Beginning of Period True-up and Interest Provision		3,509,614	3,171,084	2,182,208	2,415,448	2,016,730	1,959,085	1,554,627	1,323,739	1,094,994	998,988	668,058	501,395	3,509,614
True-up Collected or (Refunded)		(262,424)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(262,418)	(3,149,022)
End of Period, Net True-up and Int. Prov.		3,171,084	2,182,208	2,415,448	2,016,730	1,959,085	1,554,627	1,323,739	1,094,994	998,988	668,058	501,395	258,666	258,666
Beginning True-up Amount		3,509,614	3,171,084	2,182,208	2,415,448	2,016,730	1,959,085	1,554,627	1,323,739	1,094,994	998,988	668,058	501,395	
Ending True-up Amount Before Interest		3,170,874	2,181,972	2,415,218	2,016,508	1,958,878	1,554,428	1,323,404	1,094,712	998,744	667,864	501,259	258,577	
Total Beginning and Ending True-up		6,680,488	5,353,056	4,597,426	4,431,956	3,975,608	3,513,513	2,878,031	2,418,451	2,093,738	1,666,852	1,169,317	759,972	
Average True-up Amount		3,340,244	2,676,528	2,298,713	2,215,978	1,987,804	1,756,756	1,439,015	1,209,225	1,046,869	833,426	584,659	379,986	
Average Annual Interest Rate		0.0750%	0.1050%	0.1200%	0.1200%	0.1250%	0.1350%	0.2800%	0.2800%	0.2800%	0.2800%	0.2800%	0.2800%	
Interest Provision		210	236	230	222	207	199	335	282	244	194	136	89	

10% Rule Interest Provision:
0.65%

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY - 1)
Page 6 of 6

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SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD **revised 8/30/2013**
JANUARY 2013 - DECEMBER 2013
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

Northwest Florida Division

Under-recovery of purchased power costs for the period January 2013 - December 2013. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2013)(Estimated)	$	755,373

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY-2)
Page 1 of 6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 32
PARTY Florida Public Utilities Co. (FPUC) (Direct)
DESCRIPTION Curtis Young - CDY-2 (Composite)

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION **revised 8/30/2013**

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 - DECEMBER 2013

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

Schedule E1-B

MARIANNA DIVISION

			ACTUAL JANUARY 2013	ACTUAL FEBRUARY 2013	ACTUAL MARCH 2013	ACTUAL APRIL 2013	ACTUAL MAY 2013	ACTUAL JUNE 2013	Estimated JULY 2013	Estimated AUGUST 2013	Estimated SEPTEMBER 2013	Estimated OCTOBER 2013	Estimated NOVEMBER 2013	Estimated DECEMBER 2013	Total
Total System Sales - KWH			24,966,141	21,844,248	22,368,813	21,185,114	23,271,501	26,281,188	30,440,000	30,068,000	30,610,000	29,829,000	27,292,000	28,596,000	316,752,005
Total System Purchases - KWH			24,917,444	22,515,414	24,361,046	21,950,706	25,381,308	29,535,698	33,120,681	33,477,525	32,093,915	29,566,500	24,623,100	26,977,780	328,521,117
System Billing Demand - KW			97,944	97,944	97,944	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,112,832
Peak Billing Demand-KW			58,600	57,108	55,639	55,119	56,630	55,599	65,761	67,679	63,290	52,589	46,174	61,606	695,794
Purchased Power Rates:															
Energy/Environmental - $/KWH	Loss Factor	0.974	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	0.04937	
Demand and Non-Fuel:															
Capacity Charge - $/KWH			9.50000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	9.500000	
Transmission and Interconnection - $/KWH			2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	2.41760	
Distribution Charge			39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	39,736	476,832
Purchased Power Costs:															
Base Fuel Costs			1,263,013	1,141,259	1,234,810	1,112,635	1,286,525	1,497,102	1,678,817	1,696,905	1,626,773	1,498,663	1,248,093	1,367,447	16,652,042
Subtotal Fuel Costs			1,263,013	1,141,259	1,234,810	1,112,635	1,286,525	1,497,102	1,678,817	1,696,905	1,626,773	1,498,663	1,248,093	1,367,447	16,652,042
Demand and Non-Fuel Costs:															
Capacity Charge			930,468	930,468	930,468	864,500	864,500	864,500	864,500	864,500	864,500	864,500	864,500	864,500	10,571,904
Transmission and Interconection			141,671	138,064	134,513	133,256	136,909	134,416	(17,310)	163,621	153,010	127,139	111,630	148,939	1,505,858
Distribution Facilities Charge (incl. FERC l/t chrg)			41,494	41,441	41,276	41,077	41,237	41,472	42,237	42,264	42,159	41,968	41,595	41,773	499,993
Meter Reading and Processing Charge			775	775	775	775	775	775	775	775	775	775	775	775	9,300
Subtotal Demand & Non-Fuel Costs			1,114,408	1,110,748	1,107,032	1,039,608	1,043,421	1,041,163	890,202	1,071,160	1,060,444	1,034,382	1,018,500	1,055,987	12,587,055
Total System Purchased Power Costs			2,377,421	2,252,007	2,341,842	2,152,243	2,329,946	2,538,265	2,569,019	2,768,065	2,687,217	2,533,045	2,266,593	2,423,434	29,239,097
Special Costs			315	259	838	(286)	237	280	300	300	300	300	300	300	3,443
Total Costs and Charges			2,377,736	2,252,266	2,342,680	2,151,957	2,330,183	2,538,545	2,569,319	2,768,365	2,687,517	2,533,345	2,266,893	2,423,734	29,242,540
Sales Revenues - Fuel Adjustment Revenues:															
Residential<	.09876	.09876	745,459	707,787	719,204	659,211	647,277	745,888	636,106	622,971	752,839	710,274	742,963	811,107	8,501,086
Residential>	.10875	.10875	394,100	237,446	275,334	143,191	168,909	369,427	543,215	606,617	563,769	579,212	540,931	612,598	5,034,749
Commercial, Small	.09847	.09847	214,315	196,210	200,245	188,608	213,525	255,507	317,366	301,709	283,985	271,085	221,359	226,479	2,890,393
Commercial, Large	.09301	.09301	580,696	548,924	543,211	535,886	689,292	708,118	866,323	829,025	816,933	791,448	652,486	644,580	8,206,922
Industrial	.08912	.08912	437,664	368,999	375,926	450,323	457,283	415,908	538,171	515,090	509,208	501,544	455,204	454,134	5,479,454
Outside Lighting Private	.07405	.07405	25,326	25,079	24,794	25,241	24,983	25,031	24,658	24,435	24,213	24,213	24,287	24,361	296,621
Street Lighting-Public	.07468	.07468	7,770	7,770	7,775	7,785	7,805	7,805	7,094	7,094	7,094	7,020	7,169	7,094	89,275
Unbilled Fuel Revenues			101,520	(205,607)	196,775	(168,866)	219,810	73,938	0	0	0	0	150,000	220,000	587,569
Total Fuel Revenues			2,506,850	1,886,608	2,343,264	1,841,379	2,428,884	2,601,622	2,932,933	2,906,941	2,958,041	2,884,796	2,794,399	3,000,353	31,086,069
Non-Fuel Revenues			948,551	868,681	888,817	834,631	860,744	966,273	943,867	1,368,409	1,175,438	1,255,289	1,191,429	890,097	12,192,227
Total Sales Revenue			3,455,401	2,755,289	3,232,081	2,676,010	3,289,628	3,567,895	3,876,800	4,275,350	4,133,479	4,140,085	3,985,828	3,890,450	43,278,296
KWH Sales:															
Residential<	RS		7,547,116	7,165,811	7,283,589	6,676,580	6,553,498	7,554,878	6,441,000	6,308,000	7,623,000	7,192,000	7,523,000	8,213,000	86,081,472
Residential>	RS		3,626,066	2,185,023	2,531,775	1,315,649	1,554,563	3,396,095	4,995,000	5,578,000	5,184,000	5,326,000	4,974,000	5,633,000	46,299,171
Commercial, Small	GS		2,176,473	1,992,605	2,033,584	1,915,401	2,168,449	2,594,686	3,223,000	3,064,000	2,884,000	2,753,000	2,248,000	2,300,000	29,353,198
Commercial, Large	GSD		6,259,027	5,917,326	5,862,447	5,779,032	7,421,683	7,625,833	9,314,000	8,913,000	8,783,000	8,509,000	7,015,000	6,930,000	88,329,348
Industrial	GSLD		4,911,176	4,140,672	4,218,392	5,053,236	5,131,332	4,667,052	6,039,000	5,780,000	5,714,000	5,628,000	5,108,000	5,096,000	61,486,860
Outside Lighting-Private	OL,OL-2		342,233	338,761	334,913	340,951	337,462	338,130	333,000	330,000	327,000	327,000	328,000	329,000	4,006,450
Street Lighting-Public	SL-1, 2, 3		104,050	104,050	104,113	104,265	104,514	104,514	95,000	95,000	95,000	94,000	96,000	95,000	1,195,506
Total KWH Sales			24,966,141	21,844,248	22,368,813	21,185,114	23,271,501	26,281,188	30,440,000	30,068,000	30,610,000	29,829,000	27,292,000	28,596,000	316,752,005
True-up Calculation:															
Fuel Revenues			2,506,850	1,886,608	2,343,264	1,841,379	2,428,884	2,601,622	2,932,933	2,906,941	2,958,041	2,884,796	2,794,399	3,000,353	to Date 31,086,069
True-up Provision for the Period - collect/(refund)			123,130	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	1,477,604
Gross Receipts Tax Refund			0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue			2,383,720	1,763,474	2,220,130	1,718,245	2,305,750	2,478,488	2,809,799	2,783,807	2,834,907	2,761,662	2,671,265	2,877,219	29,608,465
Total Purchased Power Costs			2,377,736	2,252,266	2,342,680	2,151,957	2,330,183	2,538,545	2,569,319	2,768,365	2,687,517	2,533,345	2,266,893	2,423,734	29,242,540
True-up Provision for the Period			5,984	(488,792)	(122,550)	(433,712)	(24,433)	(60,057)	240,480	15,442	147,390	228,317	404,372	453,485	365,925
Interest Provision for the Period			(263)	(321)	(272)	(224)	(179)	(163)	(269)	(245)	(225)	(195)	(153)	(100)	(2,609)
True-up and Interest Provision															
Beginning of Period			(2,596,293)	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,619,130)	(2,480,799)	(2,210,500)	(1,859,244)	(1,331,891)	(2,596,293)
True-up Collected or (Refunded)			123,130	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	123,134	1,477,604
End of Period, Net True-up			(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,619,130)	(2,480,799)	(2,210,500)	(1,859,244)	(1,331,891)	(755,372)	(755,373)
10% Rule - Interest Provision:															-2.58%
Beginning True-up Amount			(2,596,293)	(2,467,442)	(2,833,421)	(2,833,109)	(3,143,911)	(3,045,389)	(2,982,475)	(2,619,130)	(2,480,799)	(2,210,500)	(1,859,244)	(1,331,891)	
Ending True-up Amount Before Interest			(2,467,179)	(2,833,100)	(2,832,837)	(3,143,687)	(3,045,210)	(2,982,313)	(2,618,861)	(2,480,554)	(2,210,275)	(1,859,049)	(1,331,738)	(755,272)	
Total Beginning and Ending True-up			(5,063,472)	(5,300,542)	(5,666,258)	(5,976,796)	(6,189,122)	(6,027,702)	(5,601,335)	(5,099,683)	(4,691,073)	(4,069,548)	(3,190,981)	(2,087,162)	
Average True-up Amount			(2,531,736)	(2,650,271)	(2,833,129)	(2,988,398)	(3,094,561)	(3,013,851)	(2,800,668)	(2,549,842)	(2,345,537)	(2,034,774)	(1,595,491)	(1,043,581)	
Average Annual Interest Rate			0.1250%	0.1450%	0.1150%	0.0900%	0.0700%	0.0650%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	
Monthly Average Interest Rate			0.0104%	0.0121%	0.0096%	0.0075%	0.0058%	0.0054%	0.0096%	0.0096%	0.0096%	0.0096%	0.0096%	0.0096%	
Interest Provision			(263)	(321)	(272)	(224)	(179)	(163)	(269)	(245)	(225)	(195)	(153)	(100)	

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY-2)
Page 2 of 6

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR **revised 8/30/2013**
FOR THE PERIOD JANUARY 2013 - DECEMBER 2013

SCHEDULE E1-B1

		DOLLARS				MWH				CENTS/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost												
3	Coal Car Investment												
4	Adjustments to Fuel Cost (A2, Page 1)												
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	16,652,042	17,487,383	(835,341)	-4.8%	328,521	345,001	(16,480)	-4.8%	5.06879	5.06879	0.00000	0.0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	12,587,055	13,375,859	(788,804)	-5.9%	328,521	345,001	(16,480)	-4.8%	3.83143	3.87705	(0.04562)	-1.2%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	29,239,097	30,863,242	(1,624,145)	-5.3%	328,521	345,001	(16,480)	-4.8%	8.90022	8.94584	(0.04562)	-0.5%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					328,521	345,001	(16,480)	-4.8%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Other Fuel Related Costs	3,443	72,000										
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	3,443	72,000	(68,557)	-95.2%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	29,242,540	30,935,242	(1,692,702)	-5.5%	328,521	345,001	(16,480)	-4.8%	8.90127	8.96671	(0.06544)	-0.7%
21	Net Unbilled Sales	0 *	0 *	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
22	Company Use	17,714 *	18,651 *	(937)	-5.0%	199	208	(9)	-4.3%	0.00559	0.00563	(0.00004)	-0.7%
23	T & D Losses	1,029,877 *	1,200,284 *	(170,407)	-14.2%	11,570	13,386	(1,816)	-13.6%	0.32514	0.36218	(0.03704)	-10.2%
24	SYSTEM KWH SALES	29,242,540	30,935,242	(1,692,702)	-5.5%	316,752	331,407	(14,655)	-4.4%	9.23200	9.33452	(0.10252)	-1.1%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	29,242,540	30,935,242	(1,692,702)	-5.5%	316,752	331,407	(14,655)	-4.4%	9.23200	9.33452	(0.10252)	-1.1%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	29,242,540	30,935,242	(1,692,702)	-5.5%	316,752	331,407	(14,655)	-4.4%	9.23200	9.33452	(0.10252)	-1.1%
28	GPIF**												
29	TRUE-UP**	1,477,604	1,477,604	0	0.0%	316,752	331,407	(14,655)	-4.4%	0.46649	0.44586	0.02063	4.6%
30	TOTAL JURISDICTIONAL FUEL COST	30,720,144	32,412,846	(1,692,702)	-5.2%	316,752	331,407	(14,655)	-4.4%	9.69848	9.78037	(0.08189)	-0.8%
31	Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									9.70546	9.78741	(0.08195)	-0.8%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									9.705	9.787	(0.082)	-0.8%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-2)
PAGE 3 OF 6

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD **revised 8/30/2013**
JANUARY 2013 - DECEMBER 2013
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Northeast Florida Division

Over-recovery of purchased power costs for the period January 2013 - December 2013. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2013.)(Estimated)	$	(2,685,677)

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY-2)
Page 4 of 6

FLORIDA PUBLIC UTILITIES COMPANY

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1 **revised 8/30/2013**

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

Schedule E-1b

NORTHEAST FLORIDA DIVISION

		ACTUAL Jan 2013	ACTUAL Feb 2013	ACTUAL Mar 2013	ACTUAL Apr 2013	ACTUAL May 2013	ACTUAL Jun 2013	Estimated Jul 2013	Estimated Aug 2013	Estimated Sep 2013	Estimated Oct 2013	Estimated Nov 2013	Estimated Dec 2013	Total
Total System Sales - KWH		26,579,202	23,542,693	28,606,082	23,192,791	25,326,295	30,372,979	36,508,000	36,058,000	34,244,000	31,588,000	26,020,000	25,116,000	347,154,042
CCA Purchases - KWH		873,871	686,578	1,078,805	639,052	947,823	717,953	800,000	800,000	800,000	800,000	800,000	800,000	9,744,082
Rayonier Purchases - KWH - On Peak		727,244	328,328	392,673	396,848	527,104	698,783	420,000	420,000	420,000	420,000	420,000	420,000	5,590,980
Rayonier Purchases - KWH - Off Peak		1,003,083	539,216	759,721	801,135	1,136,125	1,479,937	980,000	980,000	980,000	980,000	980,000	980,000	11,599,217
JEA Purchases - KWH		23,253,095	22,813,142	29,830,181	21,423,671	25,499,052	30,563,602	38,240,860	36,725,610	34,829,980	31,009,460	25,190,900	24,246,220	343,625,773
System Billing Demand - KW		70,246	78,714	80,326	51,654	58,195	73,920	89,900	90,600	82,300	74,300	65,600	80,200	895,955
DEMAND-KW-(network load)		86,197	105,903	102,389	78,286	85,308	103,691	106,200	108,400	95,600	89,300	75,100	97,300	1,133,674
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	
Rayonier -Energy Charge- On Peak - $/KWH		0.09047	0.04563	0.09047	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.09958	0.08812	0.09047	
Rayonier- Energy Charge - Off Peak - $/KWH		0.05822	0.04563	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	0.05822	
Base Fuel Costs - $/KWH		0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	
Energy Charge - $/KWH		0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01643	0.01162	0.01162	0.01162	
Demand and Non-Fuel:														
Demand Charge - $/KW		11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	14.31	14.31	
Customer Charge - $		39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	39,736.00	
Transmission Charge $/KW		1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	
Purchased Power Costs:	CCA Fuel Costs	38,678	30,388	47,748	28,284	41,951	31,777	35,408	35,408	35,408	35,408	35,408	35,408	431,274
	Rayonier Standby Costs	142,757	39,586	79,756	86,160	118,634	155,746	98,879	98,879	98,879	98,879	94,066	95,053	1,207,274
	JEA Base Fuel Costs	1,013,835	994,653	1,300,596	934,072	143,200	1,332,573	1,667,301	1,601,237	1,518,587	1,352,012	1,098,323	1,057,135	14,013,524
	JEA Fuel Adjustment	382,048	374,820	490,110	351,991	418,949	502,160	628,297	603,402	572,257	360,330	292,718	281,741	5,258,823
	Subtotal Fuel Costs	1,577,318	1,439,447	1,918,210	1,400,507	722,734	2,022,256	2,429,885	2,338,926	2,225,131	1,846,629	1,520,515	1,469,337	20,910,895
Demand and Non-Fuel Costs:	Demand Charge	799,399	895,765	914,110	587,822	662,259	841,210	1,023,062	1,031,028	936,574	1,063,233	938,736	1,147,662	10,840,860
	Customer Charge	39,736	39,736	39,736	39,736	39,736	39,737	39,736	39,736	39,736	39,736	39,736	39,736	476,833
	Transmission Charge	130,158	159,914	154,607	118,212	128,815	156,573	160,362	163,684	144,356	134,843	113,401	146,923	1,711,848
Subtotal Demand & Non-Fuel Costs		969,293	1,095,415	1,108,453	745,770	830,810	1,037,520	1,223,160	1,234,448	1,120,666	1,237,812	1,091,873	1,334,321	13,029,541
Total System Purchased Power Costs		2,546,611	2,534,862	3,026,663	2,146,277	1,553,544	3,059,776	3,653,045	3,573,374	3,345,797	3,084,441	2,612,388	2,803,658	33,940,436
Less Direct Billing To GSLD1 Class:	Demand	372,221	133,824	261,366	52,793	56,637	47,776	130,264	130,264	130,264	130,264	130,264	130,264	1,706,201
	Commodity	183,802	152,090	355,136	30,870	135,107	108,294	126,995	127,125	127,304	127,725	128,230	128,472	1,731,150
Net Purchased Power Costs		1,990,588	2,248,948	2,410,161	2,062,614	1,361,800	2,903,706	3,395,786	3,315,985	3,088,229	2,826,452	2,353,894	2,544,922	30,503,085
	Special Costs	16,197	17,040	51,516	15,707	39,981	75,998	20,000	20,000	20,000	20,000	20,000	20,000	336,439
Total Costs and Charges		2,006,785	2,265,988	2,461,677	2,078,321	1,401,781	2,979,704	3,415,786	3,335,985	3,108,229	2,846,452	2,373,894	2,564,922	30,839,524
Sales Revenues - Fuel Adjustment Revenues:														
RS<	.09779	962,565	926,269	970,561	907,587	890,396	1,048,397	1,188,144	1,210,146	1,103,556	1,024,737	757,283	758,945	11,748,586
RS>	.10778	429,116	304,897	364,796	254,549	310,572	586,390	837,146	799,853	747,363	660,383	528,780	529,535	6,353,380
GS	.09823	216,202	192,353	207,358	204,629	227,038	267,290	298,813	295,474	275,631	267,184	220,426	201,075	2,873,473
GSD	.09370	501,049	456,954	494,316	516,351	593,238	655,077	839,950	813,900	811,464	749,058	636,709	577,864	7,645,930
GSLD	.09045	185,963	152,687	177,737	187,768	210,780	230,779	214,378	212,931	212,388	186,337	191,583	181,905	2,345,236
OL	.06733	7,603	7,620	7,245	7,584	7,598	7,668	8,080	8,012	7,743	7,608	7,945	8,282	92,988
SL,CSL	.06713	4,828	4,828	4,845	4,957	4,969	4,973	6,378	6,378	6,445	6,378	6,378	6,310	67,667
Unbilled Fuel Revenues		140,850	(195,621)	342,734	(349,352)	531,505	(117,346)	0	0	0	0	0	0	352,770
Total Fuel Revenues (Excl. GSLD1)		2,448,176	1,849,987	2,569,592	1,734,073	2,776,096	2,683,228	3,392,889	3,346,694	3,164,590	2,901,685	2,349,104	2,263,916	31,480,030
GSLD1 Fuel Revenues		556,023	285,914	616,502	83,663	191,744	156,070	257,259	257,389	257,568	257,989	258,494	258,736	3,437,351
Non-Fuel Revenues		955,049	863,007	957,773	901,078	885,378	972,945	1,631,527	1,336,262	1,437,113	910,176	848,011	1,259,070	12,957,388
Total Sales Revenue		3,959,248	2,998,908	4,143,867	2,718,814	3,853,218	3,812,243	5,281,675	4,940,345	4,859,271	4,069,850	3,455,609	3,781,722	47,874,770
KWH Sales:	RS<	9,843,458	9,472,061	9,925,485	9,290,382	9,105,219	10,720,944	12,150,000	12,375,000	11,285,000	10,479,000	7,744,000	7,761,000	120,151,549
	RS>	3,981,444	2,828,827	3,384,562	2,366,718	2,881,477	5,440,487	7,767,000	7,421,000	6,934,000	6,127,000	4,906,000	4,913,000	58,951,515
	GS	2,203,160	1,991,950	2,110,953	2,085,158	2,311,302	2,721,087	3,042,000	3,008,000	2,806,000	2,720,000	2,244,000	2,047,000	29,290,610
	GSD	5,350,031	4,876,640	5,275,378	5,568,082	6,331,079	6,991,040	8,964,000	8,686,000	8,660,000	7,994,000	6,795,000	6,167,000	81,658,250
	GSLD	2,055,860	1,688,000	1,964,920	2,075,840	2,330,220	2,551,320	2,370,000	2,354,000	2,348,000	2,060,000	2,118,000	2,011,000	25,927,160
	GSLD1	2,960,000	2,500,000	5,760,000	1,620,000	2,180,000	1,760,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	28,780,000
	OL	113,333	113,299	112,609	112,769	112,974	114,028	120,000	119,000	115,000	113,000	118,000	123,000	1,387,012
	SL,CSL	71,916	71,916	72,175	73,842	74,024	74,073	95,000	95,000	96,000	95,000	95,000	94,000	1,007,946
	Total KWH Sales	26,579,202	23,542,693	28,606,082	23,192,791	25,326,295	30,372,979	36,508,000	36,058,000	34,244,000	31,588,000	26,020,000	25,116,000	347,154,042
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		2,448,176	1,849,987	2,569,592	1,734,073	2,776,096	2,683,228	3,392,889	3,346,694	3,164,590	2,901,685	2,349,104	2,263,916	31,480,030
True-up Provision - collect/(refund)		(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(258,636)
Gross Receipts Tax Refund														0
Fuel Revenue		2,469,729	1,871,540	2,591,145	1,755,626	2,797,649	2,704,781	3,414,442	3,368,247	3,186,143	2,923,238	2,370,657	2,285,469	31,738,666
Net Purchased Power and Other Fuel Costs		2,006,785	2,265,988	2,461,677	2,078,321	1,401,781	2,979,704	3,415,786	3,335,985	3,108,229	2,846,452	2,373,894	2,564,922	30,839,524
True-up Provision for the Period		462,944	(394,448)	129,468	(322,695)	1,395,868	(274,923)	(1,344)	32,262	77,914	76,786	(3,237)	(279,453)	899,142
Interest Provision for the Period		235	275	204	150	146	165	278	278	281	286	288	272	2,858
Beginning of Period True-up and Interest Provision		2,042,313	2,483,939	2,068,212	2,176,332	1,832,233	3,206,695	2,910,384	2,887,765	2,898,752	2,955,394	3,010,913	2,986,411	2,042,313
True-up Collected or (Refunded)		(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(21,553)	(258,636)
End of Period, Net True-up and Int. Prov.		2,483,939	2,068,212	2,176,332	1,832,233	3,206,695	2,910,384	2,887,765	2,898,752	2,955,394	3,010,913	2,986,411	2,685,677	2,685,677
Beginning True-up Amount		2,042,313	2,483,939	2,068,212	2,176,332	1,832,233	3,206,695	2,910,384	2,887,765	2,898,752	2,955,394	3,010,913	2,986,411	
Ending True-up Amount Before Interest		2,483,704	2,067,937	2,176,128	1,832,083	3,206,549	2,910,219	2,887,487	2,898,474	2,955,113	3,010,627	2,986,123	2,685,405	
Total Beginning and Ending True-up		4,526,017	4,551,876	4,244,340	4,008,415	5,038,782	6,116,914	5,797,871	5,786,239	5,853,865	5,966,021	5,997,036	5,671,816	
Average True-up Amount		2,263,008	2,275,938	2,122,170	2,004,207	2,519,391	3,058,457	2,898,936	2,893,120	2,926,933	2,983,011	2,998,518	2,835,908	
Average Annual Interest Rate		0.1250%	0.1450%	0.1150%	0.0900%	0.0700%	0.0650%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	0.1150%	
Interest Provision		235	275	204	150	146	165	278	278	281	286	288	272	

10% Rule Interest Provision:
7.91%

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(Revised CDY-2)
Page 5 of 6

SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR **revised 8/30/2013**
JANUARY 2013 - DECEMBER 2013

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)												
2 Nuclear Fuel Disposal Cost (A13)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	19,272,347	20,975,893	(1,703,546)	-8.1%	343,626	349,424	(5,798)	-1.7%	5.60852	6.00299	(0.39447)	-6.6%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	13,029,541	13,344,368	(314,827)	-2.4%	343,626	349,424	(5,798)	-1.7%	3.79178	3.81896	(0.02718)	-0.7%
11 Energy Payments to Qualifying Facilities (A8a)	1,638,548	1,469,762	168,786	11.5%	9,744	23,770	(14,026)	-59.0%	16.81597	6.18326	10.63271	172.0%
12 TOTAL COST OF PURCHASED POWER	33,940,436	35,790,023	(1,849,587)	-5.2%	353,370	373,194	(19,824)	-5.3%	9.60479	9.59019	0.01460	0.2%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					353,370	373,194	(19,824)	-5.3%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)	336,439	240,000	96,439	40.2%								
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	336,439	240,000	96,439	40.2%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	34,276,875	36,030,023	(1,753,148)	-4.9%	353,370	373,194	(19,824)	-5.3%	9.70000	9.65450	0.04550	0.5%
21 Net Unbilled Sales (A4)	(1,498,456) *	0 *	(1,498,456)	0.0%	(15,448)	0	(15,448)	0.0%	(0.43164)	0.00000	(0.43164)	0.0%
22 Company Use (A4)	44,814 *	43,156 *	1,658	3.8%	462	447	15	3.4%	0.01291	0.01208	0.00083	6.9%
23 T & D Losses (A4)	2,056,594 *	1,508,419 *	548,175	36.3%	21,202	15,624	5,578	35.7%	0.59242	0.42238	0.17004	40.3%
24 SYSTEM KWH SALES	34,276,875	36,030,023	(1,753,148)	-4.9%	347,154	357,123	(9,969)	-2.8%	9.87369	10.08896	(0.21527)	-2.1%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	34,276,875	36,030,023	(1,753,148)	-4.9%	347,154	357,123	(9,969)	-2.8%	9.87369	10.08896	(0.21527)	-2.1%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	34,276,875	36,030,023	(1,753,148)	-4.9%	347,154	357,123	(9,969)	-2.8%	9.87369	10.08896	(0.21527)	-2.1%
28 GPIF**												
29 TRUE-UP**	(258,636)	(258,636)	0	0.0%	347,154	357,123	(9,969)	-2.8%	(0.07450)	(0.07242)	(0.00208)	2.9%
30 TOTAL JURISDICTIONAL FUEL COST	34,018,239	35,771,387	(1,753,148)	-4.9%	347,154	357,123	(9,969)	-2.8%	9.79918	10.01655	(0.21737)	-2.2%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									9.80624	10.02376	(0.21752)	-2.2%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									9.806	10.024	(0.218)	-2.2%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO.
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-2)
PAGE 6 OF 6

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

SCHEDULE E1
PAGE 1 OF 2

NORTHWEST FLORIDA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	19,156,686		340,113	5.63245
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Transformation Cost of Purch Power (E2)	12,282,045		340,113	3.61117
10a	Demand Costs of Purchased Power	11,769,050	*		
10b	Transformation Energy & Customer Costs of Purchased Power	512,995	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	31,438,731		340,113	9.24361
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	31,438,731		340,113	9.24361
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	31,438,731		340,113	9.24361
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	22,092	*	239	0.00669
23	T & D Losses	893,580	*	9,667	0.27061
24	SYSTEM MWH SALES	31,438,731		330,207	9.52092
25	Less Total Demand Cost Recovery	11,769,050	***		
26	Jurisdictional MWH Sales	19,669,681		330,207	5.95677
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	19,669,681		330,207	5.95677
28	Projected Unbilled Revenues	(400,000)		330,207	(0.12114)
29	TRUE-UP **	755,373		330,207	0.22876
30	TOTAL JURISDICTIONAL FUEL COST	20,025,054		330,207	6.06439
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				6.06876
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH	20,039,472			6.069

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. _130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 1 OF 14

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 33
PARTY Florida Public Utilities Co. (FPUC) (Direct)
DESCRIPTION Curtis Young - CDY-3 (Composite)

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

NORTHWEST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	138,617,000	57.313%	27,609.6	1.089	1.030	30,066.9	142,775,510	48.99%	41.97%
35	GS	31,799,000	63.216%	5,742.3	1.089	1.030	6,253.4	32,752,970	10.19%	9.63%
36	GSD	91,397,000	73.904%	14,117.6	1.089	1.030	15,374.1	94,138,910	25.05%	27.68%
37	GSLD	62,698,000	84.021%	8,518.5	1.089	1.030	9,276.6	64,578,940	15.12%	18.99%
38	OL, OL1	4,554,000	178.492%	291.3	1.089	1.030	317.2	4,690,620	0.52%	1.38%
39	SL1, SL2 & SL3	1,142,000	178.492%	73.0	1.089	1.030	79.5	1,176,260	0.13%	0.35%
40	TOTAL	330,207,000		56,352.3			61,367.7	340,113,210	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocatio Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	45.20%	3.24%	48.44%	$5,700,927	0.04113	0.04116	0.06069	$0.10185
42	GS	9.41%	0.74%	10.15%	1,194,559	0.03757	0.03760	0.06069	$0.09829
43	GSD	23.12%	2.13%	25.25%	2,971,685	0.03251	0.03253	0.06069	$0.09322
44	GSLD	13.96%	1.46%	15.42%	1,814,788	0.02894	0.02896	0.06069	$0.08965
45	OL, OL1	0.48%	0.11%	0.59%	69,437	0.01525	0.01526	0.06069	$0.07595
46	SL1, SL2 & SL3	0.12%	0.03%	0.15%	17,654	0.01546	0.01547	0.06069	$0.07616
47	TOTAL	92.29%	7.71%	100.00%	$11,769,050				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levellzed Adj.	Revenues
48	RS	Sales	138,617,000	$0.10185	$14,118,141
49	RS	<= 1,000kWh/mo.	89,221,000	$0.09740	$8,689,736
50	RS	> 1,000 kWh/mo.	49,396,000	$0.10990	$5,428,405
51	RS	Total Sales	138,617,000		$14,118,141

TOU Rates

		(22) On Peak Rate Differential	(23) Off Peak Rate Differential	(24) Levelized Adj. On Peak	(25) Levellzed Adj. Off Peak
	Rate Schedule				
52	RS	0.0840	(0.0390)	$0.18140	$0.05840
53	GS	0.0400	(0.0500)	$0.13829	$0.04829
54	GSD	0.0400	(0.0325)	$0.13322	$0.06072
55	GSLD	0.0600	(0.0300)	$0.14965	$0.05965
56	Interruptibl	(0.0150)	-	$0.07465	$0.08965

(2) From Gulf Power Co. 2009 Load Research data results.

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2013 - DECEMBER 2013
#REF!

NORTHWEST FLORIDA DIVISION

Under-recovery of purchased power costs for the period January 2013 - December 2013. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2013; (Estimated)	$	755,373
Estimated kilowatt hour sales for the months of January 2014 - December 2014 as per estimate filed with the Commission.		330,207,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2014 - December 2014.		0.22876

Exhibit No._____
DOCKET NO. _130001-EI
Florida Public Utilities Company
(CDY-3)
Page 3 of 14

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

LINE NO.		(a) 2014 JANUARY	(b) 2014 FEBRUARY	(c) 2014 MARCH	(d) 2014 APRIL	(e) 2014 MAY	(f) 2014 JUNE	(g) 2014 JULY	(h) 2014 AUGUST	(i) 2014 SEPTEMBER	(j) 2014 OCTOBER	(k) 2014 NOVEMBER	(l) 2014 DECEMBER	(m) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION													0	1
1a	NUCLEAR FUEL DISPOSAL													0	1a
2	FUEL COST OF POWER SOLD													0	2
3	FUEL COST OF PURCHASED POWER	1,624,049	1,553,271	1,502,277	1,272,599	1,356,313	1,682,063	1,858,774	1,901,008	1,816,424	1,672,490	1,391,877	1,525,541	19,156,686	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER	1,025,596	1,024,071	1,022,392	1,022,746	1,022,923	1,024,043	1,024,166	1,023,779	1,023,743	1,023,207	1,022,643	1,022,736	12,282,045	3a
3b	QUALIFYING FACILITIES													0	3b
4	ENERGY COST OF ECONOMY PURCHASES													0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	2,649,645	2,577,342	2,524,669	2,295,345	2,379,236	2,706,106	2,882,940	2,924,787	2,840,167	2,695,697	2,414,520	2,548,277	31,438,731	5
6	LESS: TOTAL DEMAND COST RECOVERY	982,813	981,374	979,757	980,390	980,465	981,189	981,098	980,659	980,726	980,365	980,142	980,072	11,769,050	6
7	TOTAL OTHER COST TO BE RECOVERED	1,666,832	1,595,968	1,544,912	1,314,955	1,398,771	1,724,917	1,901,842	1,944,128	1,859,441	1,715,332	1,434,378	1,568,205	19,669,681	7
7a	SYSTEM KWH SOLD (MWH)	27,994	26,774	25,895	21,936	23,379	28,994	32,040	32,768	31,310	28,829	23,992	26,296	330,207	7a
7b	COST PER KWH SOLD (CENTS/KWH)	5.95425	5.96089	5.96606	5.99451	5.98302	5.94922	5.93584	5.93301	5.93881	5.95002	5.97857	5.96366	5.95677	7b
8	JURISDICTIONAL LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)	5.95425	5.96089	5.96606	5.99451	5.98302	5.94922	5.93584	5.93301	5.93881	5.95002	5.97857	5.96366	5.95677	9
10	PROJECTED UNBILLED REVENUES (CENTS/KWH)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	(0.12114)	10
11	TRUE-UP (CENTS/KWH)	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	0.22876	11
12	TOTAL	6.06187	6.06851	6.07368	6.10213	6.09064	6.05684	6.04346	6.04063	6.04643	6.05764	6.08619	6.07128	6.06439	12
13	REVENUE TAX FACTOR 0.00072	0.00436	0.00437	0.00437	0.00439	0.00439	0.00436	0.00435	0.00435	0.00435	0.00436	0.00438	0.00437	0.00437	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	6.06623	6.07288	6.07805	6.10652	6.09503	6.06120	6.04781	6.04498	6.05078	6.06200	6.09057	6.07565	6.06876	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	6.066	6.073	6.078	6.107	6.095	6.061	6.048	6.045	6.051	6.062	6.091	6.076	6.069	15

EXHIBIT NO. _____
DOCKET NO. _130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 4 OF 14

SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
NORTHWEST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2014	GULF POWER COMPANY	RE	28,833,820			28,833,820	5.632445	9.188325	1,624,049
FEBRUARY 2014	GULF POWER COMPANY	RE	27,577,220			27,577,220	5.632442	9.344822	1,553,271
MARCH 2014	GULF POWER COMPANY	RE	26,671,850			26,671,850	5.632445	9.464544	1,502,277
APRIL 2014	GULF POWER COMPANY	RE	22,594,080			22,594,080	5.632444	10.157727	1,272,599
MAY 2014	GULF POWER COMPANY	RE	24,080,370			24,080,370	5.632442	9.879151	1,356,313
JUNE 2014	GULF POWER COMPANY	RE	29,863,820			29,863,820	5.632443	9.060482	1,682,063
JULY 2014	GULF POWER COMPANY	RE	33,001,200			33,001,200	5.632445	8.734955	1,858,774
AUGUST 2014	GULF POWER COMPANY	RE	33,751,040			33,751,040	5.632444	8.664880	1,901,008
SEPTEMBER 2014	GULF POWER COMPANY	RE	32,249,300			32,249,300	5.632445	8.805980	1,816,424
OCTOBER 2014	GULF POWER COMPANY	RE	29,693,870			29,693,870	5.632440	9.077284	1,672,490
NOVEMBER 2014	GULF POWER COMPANY	RE	24,711,760			24,711,760	5.632442	9.769515	1,391,877
DECEMBER 2014	GULF POWER COMPANY	RE	27,084,880			27,084,880	5.632443	9.407378	1,525,541
TOTAL			340,113,210	0	0	340,113,210	5.632444	9.242549	19,156,686

EXHIBIT NO. _____
DOCKET NO. _130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 5 OF 14

FLORIDA PUBLIC UTILITIES COMPANY

NORTHWEST FLORIDA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

	JANUARY 2014	FEBRUARY 2014	MARCH 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014
BASE RATE REVENUES ** $	32.58	32.58	32.58	32.58	32.58	32.58	32.58
FUEL RECOVERY FACTOR CENTS/KWH	9.74	9.74	9.74	9.74	9.74	9.74	9.74
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	97.40	97.40	97.40	97.40	97.40	97.40	97.40
GROSS RECEIPTS TAX	3.33	3.33	3.33	3.33	3.33	3.33	3.33
TOTAL REVENUES *** $	133.31	133.31	133.31	133.31	133.31	133.31	133.31

	AUGUST 2014	SEPTEMBER 2014	OCTOBER 2014	NOVEMBER 2014	DECEMBER 2014	PERIOD TOTAL
BASE RATE REVENUES ** $	32.58	32.58	32.58	32.58	32.58	390.96
FUEL RECOVERY FACTOR CENTS/KWH	9.74	9.74	9.74	9.74	9.74	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	97.40	97.40	97.40	97.40	97.40	1,168.80
GROSS RECEIPTS TAX	3.33	3.33	3.33	3.33	3.33	39.96
TOTAL REVENUES *** $	133.31	133.31	133.31	133.31	133.31	1,599.72

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.000
	32.58

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. _130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 6 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

NORTHEAST FLORIDA DIVISION

		(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	13,229,387	303,426	4.36000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Non Fuel Cost of Purch Power (E2)	18,589,672	303,426	6.12659
10a	Demand Costs of Purchased Power	14,467,027 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	4,122,645 *		
11	Energy Payments to Qualifying Facilities (E8a)	1,453,939	24,000	6.05808
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	33,272,998	327,426	10.16199
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	33,272,998	327,426	10.16199
14	Fuel Cost of Economy Sales (E6)			
15	Gain on Economy Sales (E6)			
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17	Fuel Cost of Other Power Sales			
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19	Net Inadvertent Interchange			
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	33,272,998	327,426	10.16199
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	45,424 *	447	0.01394
23	T & D Losses	123,773 *	1,218	0.03800
24	SYSTEM MWH SALES	33,272,998	325,761	10.21393
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	33,272,998	325,761	10.21393
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	33,272,998	325,761	10.21393
27a	GSLD1 MWH Sales		32,604	
27b	Other Classes MWH Sales		293,157	
27c	GSLD1 CP KW		518,416 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	(2,685,677)	325,761	-0.82443
30	TOTAL JURISDICTIONAL FUEL COST	30,587,321	325,761	9.38950
30a	Demand Purchased Power Costs (Line 10a)	14,467,027 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	18,805,971 *		
30c	True up Over/Under Recovery (Line 29)	(2,685,677) *		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 7 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

	NORTHEAST FLORIDA DIVISION	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	14,467,027		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $2.96)	2,736,640	518,416 (KW)	$5.28 /KW
33	Balance to Other Classes	11,730,387	293,157	4.00140
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	18,805,971		
35	Total KWH Purchased (Line 12)		327,426	
36	Average Cost per KWH Purchased			5.74358
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			5.91934
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,929,941	32,604	5.91934
39	Balance to Other Classes	16,876,030	293,157	5.75665
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	2,736,640	518,416 (KW)	$5.28 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$5.28 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,929,941	32,604	5.91934
40e	Total Non-demand Costs Including True-up	1,929,941	32,604	5.91934
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			5.92360
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	28,606,417	293,157	9.75805
41b	Less: Total Demand Cost Recovery	11,730,387 ***		
41c	Total Other Costs to be Recovered	16,876,030	293,157	5.75665
41d	Other Classes' Portion of True-up (Line 30c)	(2,685,677)	293,157	-0.91612
41e	Total Demand & Non-demand Costs Including True-up	14,190,353	293,157	4.84053
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	14,200,570		4.844

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 8 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

NORTHEAST FLORIDA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*8,760)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	167,482,000	57.599%	33,193.2	1.089	1.030	36,147.4	172,506,460	64.69%	57.13%
45	GS	27,306,000	75.719%	4,116.7	1.089	1.030	4,483.1	28,125,180	8.02%	9.31%
46	GSD	74,156,000	78.538%	10,778.6	1.089	1.030	11,737.9	76,380,680	21.00%	25.30%
47	GSLD	22,020,000	77.959%	3,224.4	1.089	1.030	3,511.4	22,680,600	6.28%	7.51%
48	OL	1,222,000	4996.200%	2.8	1.089	1.030	3.0	1,258,660	0.01%	0.42%
49	SL	971,000	4996.200%	2.2	1.089	1.030	2.4	1,000,130	0.00%	0.33%
	TOTAL	293,157,000		51,317.9			55,885.2	301,951,710	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (9)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
50	RS	59.71%	4.39%	64.10%	$7,519,178	0.04490	0.04493	0.04844	0.09337
51	GS	7.40%	0.72%	8.12%	952,507	0.03488	0.03491	0.04844	0.08335
52	GSD	19.38%	1.95%	21.33%	2,502,092	0.03374	0.03376	0.04844	0.08220
53	GSLD	5.80%	0.58%	6.38%	748,399	0.03399	0.03401	0.04844	0.08245
54	OL	0.01%	0.03%	0.04%	4,692	0.00384	0.00384	0.04844	0.05228
55	SL	0.00%	0.03%	0.03%	3,519	0.00362	0.00362	0.04844	0.05206
	TOTAL	92.30%	7.70%	100.00%	$11,730,387				

Step Rate Allocation for Residential Customers

		(18)		(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation		Annual kWh	Levelized Adj.	Revenues
48	RS	Sales		167,482,000	$0.09337	$15,637,794
49	RS	<= 1,000kWh/mo.		119,001,000	$0.08975	$10,680,533
50	RS	> 1,000 kWh/mo.		48,481,000	$0.10225	$4,957,261
51	RS	Total Sales		167,482,000		$15,637,794

(2) From Florida Power & Light Co. 2010 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 9 OF 14

Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2013 - DECEMBER 2013
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

NORTHEAST FLORIDA DIVISION

Over-recovery of purchased power costs for the period January 2013 - December 2013. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2013.)(Estimated)	$	(2,685,677)
Estimated kilowatt hour sales for the months of January 2014-December 2014 as per estimate filed with the Commission. (Excludes GSLD1 customers)		293,157,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2014 - December 2014		-0.91612

Exhibit No._____
DOCKET NO. 130001-EI
Florida Public Utilities Company
(CDY-3)
Page 10 of 14

SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		1,037,634	1,052,884	1,044,782	883,823	963,814	1,174,184	1,396,203	1,376,968	1,255,018	1,166,214	925,799	952,064	13,229,387	3
3a	DEMAND & NON FUEL COST OF PUR POWER		1,672,335	1,698,280	1,514,829	1,346,220	1,429,065	1,577,508	1,729,676	1,707,481	1,660,041	1,512,917	1,312,337	1,428,983	18,589,672	3a
3b	QUALIFYING FACILITIES		121,609	90,438	121,609	125,436	125,436	125,436	125,436	125,436	125,436	125,436	120,622	121,609	1,453,939	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		2,831,578	2,841,602	2,681,220	2,355,479	2,518,315	2,877,128	3,251,315	3,209,885	3,040,495	2,804,567	2,358,758	2,502,656	33,272,998	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,157,788	1,179,669	879,018	872,666	934,192	907,210	1,119,566	1,102,497	968,200	964,102	827,596	817,883	11,730,386	5a
5b	TOTAL OTHER COST TO BE RECOVERED		1,673,790	1,661,933	1,802,202	1,482,813	1,584,123	1,969,918	2,131,749	2,107,388	2,072,295	1,840,465	1,531,162	1,684,773	21,542,612	5b
6	APPORTIONMENT TO GSLD1 CLASS		349,407	345,983	468,725	350,935	350,316	468,421	348,125	348,195	468,044	349,102	350,018	469,310	4,666,582	6
6a	BALANCE TO OTHER CLASSES		1,324,383	1,315,950	1,333,477	1,131,878	1,233,807	1,501,497	1,783,624	1,759,193	1,604,251	1,491,363	1,181,144	1,215,463	16,876,030	6a
6b	SYSTEM KWH SOLD (MWH)		25,150	25,174	24,697	22,459	23,819	28,731	34,657	33,410	31,854	28,716	23,935	23,159	325,761	6b
7	GSLD1 MWH SOLD		2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	2,717	32,604	7
7a	BALANCE MWH SOLD OTHER CLASSES		22,433	22,457	21,980	19,742	21,102	26,014	31,940	30,693	29,137	25,999	21,218	20,442	293,157	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		5.90373	5.85987	6.06678	5.73335	5.84687	5.77188	5.5843	5.73158	5.50589	5.73623	5.56671	5.94591	5.75665	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		5.90373	5.85987	6.06678	5.73335	5.84687	5.77188	5.58430	5.73158	5.50589	5.73623	5.56671	5.94591	5.75665	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	(2,685,677)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	(0.91612)	11
12	TOTAL		4.98761	4.94375	5.15066	4.81723	4.93075	4.85576	4.66818	4.81546	4.58977	4.82011	4.65059	5.02979	4.84053	12
13	REVENUE TAX FACTOR	0.00072	0.00359	0.00356	0.00371	0.00347	0.00355	0.00350	0.00336	0.00347	0.00330	0.00347	0.00335	0.00362	0.00349	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		4.99120	4.94731	5.15437	4.82070	4.93430	4.85926	4.67154	4.81893	4.59307	4.82358	4.65394	5.03341	4.84402	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		4.991	4.947	5.154	4.821	4.934	4.859	4.672	4.819	4.593	4.824	4.654	5.033	4.844	15

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 11 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	23,798,955			23,798,955	4.359998	11.386924	1,037,634
FEBRUARY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	24,148,719			24,148,719	4.359999	11.392588	1,052,884
MARCH 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	23,962,895			23,962,895	4.359999	10.681560	1,044,782
APRIL 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	20,271,160			20,271,160	4.360002	11.001063	883,823
MAY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	22,105,815			22,105,815	4.360002	10.824659	963,814
JUNE 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	26,930,820			26,930,820	4.360001	10.217632	1,174,184
JULY 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	32,023,000			32,023,000	4.360001	9.761356	1,396,203
AUGUST 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,581,833			31,581,833	4.360000	9.766529	1,376,968
SEPTEMBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	28,784,807			28,784,807	4.360001	10.127075	1,255,018
OCTOBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	26,748,032			26,748,032	4.359999	10.016180	1,166,214
NOVEMBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	21,233,919			21,233,919	4.360001	10.540381	925,799
DECEMBER 2014	JACKSONVILLE ELECTRIC AUTHORITY	MS	21,836,320			21,836,320	4.360002	10.904067	952,064
TOTAL			303,426,275	0	0	303,426,275	4.360000	10.486587	13,229,387

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 12 OF 14

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.080450	6.080450	121,609
FEBRUARY 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	4.521900	4.521900	90,438
MARCH 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.080450	6.080450	121,609
APRIL 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
MAY 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
JUNE 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
JULY 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
AUGUST 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
SEPTEMBER 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
OCTOBER 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.271800	6.271800	125,436
NOVEMBER 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.031100	6.031100	120,622
DECEMBER 2014	ROCK-TENN COMPANY / RAYONIER		2,000,000			2,000,000	6.080450	6.080450	121,609
TOTAL			24,000,000	0	0	24,000,000	6.058079	6.058079	1,453,939

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 13 OF 14

SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
NORTHEAST FLORIDA DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

	JANUARY 2014	FEBRUARY 2014	MARCH 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014
BASE RATE REVENUES ** $	32.58	32.58	32.58	32.58	32.58	32.58	32.58
FUEL RECOVERY FACTOR CENTS/KWH	8.98	8.98	8.98	8.98	8.98	8.98	8.98
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	89.75	89.75	89.75	89.75	89.75	89.75	89.75
GROSS RECEIPTS TAX	3.14	3.14	3.14	3.14	3.14	3.14	3.14
TOTAL REVENUES *** $	125.47	125.47	125.47	125.47	125.47	125.47	125.47

	AUGUST 2014	SEPTEMBER 2014	OCTOBER 2014	NOVEMBER 2014	DECEMBER 2014	PERIOD TOTAL
BASE RATE REVENUES ** $	32.58	32.58	32.58	32.58	32.58	390.96
FUEL RECOVERY FACTOR CENTS/KWH	8.98	8.98	8.98	8.98	8.98	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	89.75	89.75	89.75	89.75	89.75	1,077.00
GROSS RECEIPTS TAX	3.14	3.14	3.14	3.14	3.14	37.68
TOTAL REVENUES *** $	125.47	125.47	125.47	125.47	125.47	1,505.64

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	12.00
CENTS/KWH	19.58
CONSERVATION FACTOR	1.000
	32.58

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 130001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(CDY-3)
PAGE 14 OF 14

Exhibit 34 was Withdrawn

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 34
PARTY Florida Public Utilities Co. (FPUC) (Direct)
DESCRIPTION Cheryl M. Martin - CMM-1 (Composite)

Florida Public Utilities
Schedule of Revenue Requirements for Transmission Plant

Schedule C

Gross Value of the Tangible and Intangible Property			$ 9,499,372
Accum. Depr. of the Tangible and Intangible Property			(3,445,185)
Net Value of the Tangible and Intangible Property			$ 6,054,187
	Cost of capital		
Equity Component	8.44%		$ 510,920
Debt Component	2.19%		132,587
Operating Costs			943,891
Total Revenue Requirement			**$ 1,587,399**

Transmission Cost Distribution:	**Northwest Florida**	**Northeast Florida**
Pre-Distributed Costs	$ 1,588,901	$ 1,914,049
Distribution: NW Fl.@ 50% to NE Fl.	(794,451)	794,451
Transmission Costs per Fuel Filing	**$ 794,450**	**$ 2,708,500**
NE Fl. Transmission costs embedded in Base Rates	794,451	(794,451)
Net Transmission Costs	$ 1,588,901	$ 1,914,049

Plant Assets	Amount
Land Rights	$ 23,842
Structures and Improvements	144,150
Station Equipment	3,492,402
Towers and Fixtures	326,682
Poles and Fixtures-Concrete	602,993
Poles and Fixtures-Wood	2,459,894
Overhead Conductors and Devices	2,442,621
Roads and Trails	6,788
Total Plant	**$ 9,499,372**

Reserve	Depr. Rates	Depr Exp	Accum. Amount
Land Rights	2.300%	$ 548	$ (18,687)
Structures and Improvements	1.800%	2,595	(14,772)
Station Equipment	2.400%	83,818	(1,169,254)
Towers and Fixtures	1.800%	5,880	(183,580)
Poles and Fixtures-Concrete	2.138%	12,892	16,315
Poles and Fixtures-Wood	2.431%	59,800	(1,288,704)
Overhead Conductors and Devices	2.095%	51,173	(781,054)
Roads and Trails	1.500%	102	(5,449)
Total Depreciation Exp / Reserve		**$ 216,808**	**$ (3,445,185)**

Overall Weighted Cost Rate	
Equity Cost Rate	11.00%
Weighted Equity Cost Rate	5.18%
Revenue Expansion Factor @	1.629175
Weighted Equity Cost Rate	8.44%
Weighted Debt Cost Rate	2.19%
Overall Weighted Cost Rate	7.37%

Operating Costs	Amount
Operating Expenses (Transmission) - Estimated	$ 255,000
Maintenance Expenses (Transmission) - Estimated	351,000
Depreciation Expense	216,808
Property Taxes @ 2%	121,084
Total Operating Costs	**$ 943,891**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 35
PARTY Florida Public Utilities Co. (FPUC) (Direct)
DESCRIPTION P. Mark Cutshaw - PMC-1

EXHIBIT NO._____
DOCKET NO. 130001-E1
FLORIDA PUBLIC UTILITIES COMPANY
(PMC-1)
PAGE 1 of 1

GULF POWER COMPANY COAL SUPPLIERS
January 1, 2012 – December 31, 2012

Contract Coal Suppliers	Tons Recieved (1)(2)	
The American Coal Company	255,740	
Interocean Coal Sales, LDC	102,231	
Foresight Coal Sales	377,879	
Patriot Coal Sales, LDC	537,440	
West Ridge Resources	22,470	
Oxbow Carbon	254,090	
Rio Tinto, PRB Mine (Plant Daniel)	48,124	
Twentymile Coal Company (Plant Daniel)	326,140	
Oxbow Carbon & Minerals (Plant Daniel)	94,546	
TOTAL Contract Coal		2,018,661
Spot Coal Suppliers	Tons Received (1)(2)	
TOTAL Spot Coal		0
GRAND TOTAL COAL RECEIPTS		2,018,661

(1) Data from Monthly FPSC 423 Reports.
(2) Plant Daniel tons represent Gulf's 50% share of purchases.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 36
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION H.R. Ball - HRB-1

Gulf Contract Coal Supply Data from FPSC 423

	Supplier	Plant	Shipped Quantity (tons)	Actual Average Heating Value	(A) Weighted Avg Price $/MMBTU)
1	American Coal Company	Crist	255,740	11884	[redacted]
2	Foresight Coal Sales	Crist	377,879	11717	
3	Oxbow Carbon	Crist	214,932	12120	
4	Patriot Coal Sales, LDC	Crist	298,405	11938	
5	West Ridge Resources	Crist	22,470	11993	
6	**Weighted Average Price**	**Crist**	**1,169,426**	**11889**	**$4.074**
7	Interocean Coal Sales	Smith	102,231	11220	[redacted]
8	Oxbow Carbon	Smith	39,158	12502	
9	Patriot Coal Sales, LDC	Smith	239,035	11954	
10	**Weighted Average Price**	**Smith**	**380,424**	**11813**	**$5.245**
11	**Weighted Average Price**	**Scholz**	**0**	**N/A**	**N/A**

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit HRB-1, Page 2 of 5
Schedule 2, Page 1 of 2

Gulf Contract Coal Supply Data from FPSC 423

					(A)
1	Twentymile Coal Co.	Daniel (Gulf 50%)	326,140	11186	[redacted]
2	Rio Tinto	Daniel (Gulf 50%)	48,124	8807	
3	Oxbow Carbon	Daniel (Gulf 50%)	94,546	12146	
4	**Weighted Average Price**	**Daniel (Gulf 50%)**	**468,811**	**11135**	**$4.841**

Gulf Spot Coal Supply Data from FPSC 423

	Supplier	Plant	Shipped Quantity (tons)	Guaranteed Heating Value	Weighted Avg Price $/MMBTU)
5	None	None	0	N/A	N/A
6	**Weighted Average Price**				**N/A**

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit HRB-1, Page 3 of 5
Schedule 2, Page 2 of 2

Gulf Natural Gas Purchase Price Variance
Actual Gas Price vs. Market Gas Price

Gulf Gas Purchase data for Smith 3 taken from Schedules A-5 and for Central Alabama from the monthly gas invoice.

	Gulf Actual Purchases MMBtu	Gas Purchases Gulf Actual Delivered Cost (Total Dollars)	Monthly Gas Hedge Settlement (Total Dollars)	Gulf Actual Gas Purchases Weighted Average Commodity $/MMBtu	Gulf Actual Gas Storage and Transportation $/MMBtu	Gulf Actual Purchases Delivered Cost $/MMBtu	Gulf Actual Hedged Purchases Delivered Cost $/MMBtu	FGT Zone 3 Weighted Average Market Price Commodity $/MMBtu	FGT Zone 3 Market Price + $0.50 Storage and Transportation $/MMBtu
Jan-12	6,042,663	$ 18,488,628	$ 2,673,650	$2.90	$0.16	$3.06	$3.50	$2.72	$3.22
Feb-12	6,182,796	$ 17,550,873	$ 2,994,705	$2.69	$0.15	$2.84	$3.32	$2.55	$3.05
Mar-12	6,565,761	$ 15,869,801	$ 3,514,941	$2.27	$0.15	$2.42	$2.95	$2.32	$2.82
Apr-12	4,048,367	$ 11,075,559	$ 3.254,010	$2.12	$0.62	$2.74	$3.54	$2.21	$2.71
May-12	6,093,828	$ 18,274,993	$ 3,284,575	$2.55	$0.45	$3.00	$3.54	$2.66	$3.16
Jun-12	6,169,779	$ 18,747,262	$ 3,610,712	$2.66	$0.38	$3.04	$3.62	$2.74	$3.24
Jul-12	6,513,349	$ 23,137,031	$ 2,598,950	$3.13	$0.42	$3.55	$3.95	$3.25	$3.75
Aug-12	6,513,802	$ 22,296,881	$ 2,886,418	$3.01	$0.41	$3.42	$3.87	$3.09	$3.59
Sep-12	5,984,344	$ 20,455,656	$ 2,922,638	$2.99	$0.43	$3.42	$3.91	$3.08	$3.58
Oct-12	4,745,362	$ 19,012,981	$ 1,891,416	$3.50	$0.51	$4.01	$4.41	$3.60	$4.10
Nov-12	5,064,266	$ 21,111,860	$ 1,268,335	$3.73	$0.44	$4.17	$4.42	$3.59	$4.09
Dec-12	6,309,814	$ 24,352,478	$ 1,965,204	$3.48	$0.38	$3.86	$4.17	$3.37	$3.87
TOTAL	**70,234,131**	**$ 230,374,003**	**$ 32,865,554**	**$2.92**	**$0.36**	**$3.28**	**$3.75**	**$2.93**	**$3.43**

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit HRB-1, Page 4 of 5
Schedule 3

2012 Natural Gas Burn Cost Variance and Hedging Effectiveness

Hedging Settlement Cost from Schedule A-1

NOTE: Gas Burn Cost and Gas MMBTU's burned is billed amount for Gulf owned gas fired generation and purchase power agreement (PPA) combined cycle generating units for which Gulf supplies the fuel. This is the first year that Gulf has hedged natural gas supply for the PPA units.

	Gas Burn for Generation MMBtu	Gas Cost for Generation Actual Cost	Gulf Hedge Settlement Total $	Gas Cost for Generation Hedged Cost	Gas Cost of Generation Unhedged $/MMBtu	Gas Cost of Generation Hedged $/MMBtu
Jan-12	**6,068434**	$ 19,174,768	$ 2,673,650	$ 21,848,418	$ 3.16	$ 3.60
Feb-12	**6,182,796**	$ 17,998,219	$ 2,994,705	$ 20,992,924	$ 2.91	$ 3.40
Mar-12	**6,532,507**	$ 16,358,792	$ 3,514,941	$ 19,873,733	$ 2.50	$ 3.04
Apr-12	**4,048,367**	$ 11,147,007	$ 3,254,010	$ 14,401,017	$ 2.75	$ 3.56
May-12	**6,093,828**	$ 18,528,580	$ 3,284,575	$ 21,813,155	$ 3.04	$ 3.58
Jun-12	**6,272,941**	$ 19,577,357	$ 3,610,712	$ 23,188,069	$ 3.12	$ 3.70
Jul-12	**6,511,519**	$ 23,345,626	$ 2,598,950	$ 25,944,576	$ 3.59	$ 3.98
Aug-12	**6,596,603**	$ 23,252,657	$ 2,886,418	$ 26,139,075	$ 3.52	$ 3.96
Sep-12	**6,049,330**	$ 21,307,480	$ 2,922,638	$ 24,230,118	$ 3.52	$ 4.01
Oct-12	**4,763,688**	$ 19,260,215	$ 1,891,416	$ 21,151,631	$ 4.04	$ 4.44
Nov-12	**5,161,918**	$ 21,837,955	$ 1,268,335	$ 23,106,290	$ 4.23	$ 4.48
Dec-12	**6,200,472**	$ 24,173,815	$ 1,965,204	$ 26,139,019	$ 3.90	$ 4.22
TOTAL	**70,482,403**	**$ 235,962,471**	**$ 32,865,554**	**$ 268,828,025**		

Weighted Average Price	**$ 3.35**	**$ 3.81**

Variance	**0.28**	**0.18**
Standard Deviation	**0.53**	**0.43**

Schedule 1

GULF POWER COMPANY
PROJECTED VS. ACTUAL FUEL COST OF SYSTEM NET GENERATION

Cents / KWH Fuel Cost

Period Ending	Projected[1]	Actual[1]	% Difference[1]
December 2003	1.9639	2.1133	7.61
December 2004	2.0936	2.3270	11.15
December 2005	2.6566	2.8817	8.47
December 2006	2.9215	3.0902	5.77
December 2007	3.3156	3.2959	(0.59)
December 2008	3.7567	4.2044	11.92
December 2009	4.5498	4.2774	(5.99)
December 2010	4.9626	4.8818	1.66
December 2011	4.7917	4.7259	1.37
December 2012	4.2617	3.9806	(0.28)
December 2013	4.2729[2]		
December 2014	4.0181[3]		

(1) Line No. 1 from FPSC Schedule A-1, December, Period To Date
(2) Line No. 1 from FPSC Schedule E-1B-1, 2013 Actual / Estimated True-Up
(3) Line No. 1 from FPSC Schedule E-1, 2014 Projection Filing

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 37
PARTY Gulf Power Company (Gulf) Direct)
DESCRIPTION H.R. Ball - HRB-2

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	SHELL	2213	Option (Collar)			Nymex LD HH		Nymex	08/2012	20000	
2	SHELL	2213				Nymex LD HH	Call Price Buy Down		08/2012	20000	
3	SHELL	2214				Nymex LD HH		Nymex	08/2012	20000	
4	JPMORG	2234	Option (Collar)			Nymex LD HH		Nymex	08/2012	20000	
5	JPMORG	2235				Nymex LD HH		Nymex	08/2012	20000	
6	JPMORG	2245	Option (Collar)			Nymex LD HH		Nymex	08/2012	20000	
7	JPMORG	2246				Nymex LD HH		Nymex	08/2012	20000	
8	BBVA	2257	Option (Collar)			Nymex LD HH		Nymex	08/2012	40000	
9	BBVA	2258				Nymex LD HH		Nymex	08/2012	40000	
10	CIBC	2285	Option (Collar)			Nymex LD HH		Nymex	08/2012	20000	
11	CIBC	2286				Nymex LD HH		Nymex	08/2012	20000	
12	JPMORG	2344	Option (Collar)			Nymex LD HH		Nymex	08/2012	30000	
13	JPMORG	2345				Nymex LD HH		Nymex	08/2012	30000	
14	SHELL	2353	Option (Collar)			Nymex LD HH		Nymex	08/2012	30000	
15	SHELL	2354				Nymex LD HH		Nymex	08/2012	30000	
16	JPMORG	2358	Option (Collar)			Nymex LD HH		Nymex	08/2012	30000	
17	JPMORG	2359				Nymex LD HH		Nymex	08/2012	30000	
18	BMO	2368	Option (Collar)			Nymex LD HH		Nymex	08/2012	20000	
19	BMO	2369				Nymex LD HH		Nymex	08/2012	20000	
20	SHELL	2585	Option (Collar)			Nymex LD HH		Nymex	08/2012	40000	
21	SHELL	2586				Nymex LD HH		Nymex	08/2012	40000	
22	JPMORG	2587	Option (Collar)			Nymex LD HH		Nymex	08/2012	40000	
23	JPMORG	2588				Nymex LD HH		Nymex	08/2012	40000	
24	FIFTH	2589	Option (Collar)			Nymex LD HH		Nymex	08/2012	40000	
25	FIFTH	2590				Nymex LD HH		Nymex	08/2012	40000	
26	JPMORG	1069	Swap	Fixed		Nymex LD HH		Nymex	08/2012	90000	
27	SUISSE	1091	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
28	SUISSE	1111	Swap	Fixed		Nymex LD HH		Nymex	08/2012	50000	
29	JPMORG	1222	Swap	Fixed		Nymex LD HH		Nymex	08/2012	10000	
30	MERRIL	5154	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
31	DEUTSCH	5204	Swap	Fixed		Nymex LD HH		Nymex	08/2012	10000	
32	SUISSE	5602	Swap	Fixed		Nymex LD HH		Nymex	08/2012	10000	
33	SUISSE	5889	Swap	Fixed		Nymex LD HH		Nymex	08/2012	10000	
34	JPMORG	5934	Swap	Fixed		Nymex LD HH		Nymex	08/2012	80000	
35	JPMORG	5976	Swap	Fixed		Nymex LD HH		Nymex	08/2012	50000	
36	SHELL	5981	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
37	JPMORG	5982	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
38	JPMORG	6064	Swap	Fixed		Nymex LD HH		Nymex	08/2012	110000	
39	SUISSE	6099	Swap	Fixed		Nymex LD HH		Nymex	08/2012	50000	
40	JPMORG	6177	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
41	SHELL	6197	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
42	CITIGR	6206	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
43	BARCLAY	6229	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
44	JPMORG	6235	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
45	SHELL	6271	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
46	CITIGR	6291	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
47	JPMORG	6374	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
48	BBVA	6401	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
49	BBVA	6451	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
50	CITIGR	6482	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
51	CITIGR	6592	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
52	JPMORG	6607	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
53	CIBC	6648	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
54	JPMORG	6737	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
55	MERRIL	6754	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
56	JPMORG	7084	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
57	CIBC	7088	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
58	JPMORG	7098	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
59	JPMORG	7107	Swap	Fixed		Nymex LD HH		Nymex	08/2012	50000	
60	BARCLAY	7119	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
61	CIBC	7127	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
62	MORGAN	7136	Swap	Fixed		Nymex LD HH		Nymex	08/2012	20000	
63	CIBC	7143	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
64	FIFTH	7168	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
65	CIBC	7182	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
66	JPMORG	7196	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
67	CIBC	7205	Swap	Fixed		Nymex LD HH		Nymex	08/2012	30000	
68	FIFTH	7359	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
69	BMO	7377	Swap	Fixed		Nymex LD HH		Nymex	08/2012	50000	
70	BMO	7386	Swap	Fixed		Nymex LD HH		Nymex	08/2012	50000	
71	BMO	7434	Swap	Fixed		Nymex LD HH		Nymex	08/2012	40000	
72	BP	7627	Swap	Fixed		Nymex LD HH		Nymex	08/2012	300000	
73	CIBC	7675	Swap	Fixed		Nymex LD HH		Nymex	08/2012	200000	
74	CIBC	7686	Swap	Fixed		Nymex LD HH		Nymex	08/2012	200000	
75	CIBC	7698	Swap	Fixed		Nymex LD HH		Nymex	08/2012	300000	
76	SHELL	7773	Swap	Nymex LD HH		GD HH		Gas Daily	08/2012	310000	
77	CITIGR	7777	Swap	Nymex LD HH		GD HH		Gas Daily	08/2012	310000	
78	MERRIL	7779	Swap	Nymex LD HH		Fixed		Nymex	08/2012	320000	

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 38
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION H.R. Ball - HRB-3

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	MERRIL	7779	Swap	Fixed		Nymex LD HH		Nymex	08/2012	330000	
2	JPMORG	7781	Swap	Fixed		Nymex LD HH		Nymex	08/2012	330000	
3	JPMORG	7781	Swap	Nymex LD HH		Fixed		Nymex	08/2012	330000	
4	CIBC	7782	Swap	Nymex LD HH		Fixed		Nymex	08/2012	330000	
5	CIBC	7782	Swap	Fixed		Nymex LD HH		Nymex	08/2012	330000	
6	SUISSE	7783	Swap	Fixed		Nymex LD HH		Nymex	08/2012	330000	
7	SUISSE	7783	Swap	Nymex LD HH		Fixed		Nymex	08/2012	330000	
8	BMO	7785	Swap	Fixed		Nymex LD HH		Nymex	08/2012	330000	
9	BMO	7785	Swap	Nymex LD HH		Fixed		Nymex	08/2012	330000	
10	BARCLAY	7792	Swap	Fixed		Nymex LD HH		Nymex	08/2012	370000	
11	BARCLAY	7792	Swap	Nymex LD HH		Fixed		Nymex	08/2012	370000	
12	JPMORG	7802	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
13	MERRIL	7803	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
14	DEUTSCH	7813	Swap	Nymex LD HH		Fixed		Nymex	08/2012	60000	
15	CIBC	7826	Swap	Nymex LD HH		Fixed		Nymex	08/2012	190000	
16	DEUTSCH	7831	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
17	CITIGR	7833	Swap	Nymex LD HH		Fixed		Nymex	08/2012	60000	
18	FIFTH	7834	Swap	Nymex LD HH		Fixed		Nymex	08/2012	60000	
19	BP	7836	Swap	Nymex LD HH		Fixed		Nymex	08/2012	60000	
20	CIBC	7840	Swap	Nymex LD HH		Fixed		Nymex	08/2012	180000	
21	FIFTH	7849	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
22	CITIGR	7861	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
23	DEUTSCH	7863	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
24	SHELL	7864	Swap	Nymex LD HH		Fixed		Nymex	08/2012	60000	
25	CIBC	7876	Swap	Nymex LD HH		Fixed		Nymex	08/2012	180000	
26	SCOTIA	7877	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
27	BP	7878	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
28	DEUTSCH	7882	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
29	CITIGR	7885	Swap	Nymex LD HH		Fixed		Nymex	08/2012	70000	
30	SUISSE	7900	Swap	Nymex LD HH		Fixed		Nymex	08/2012	210000	
31	MERRIL	7903	Swap	Nymex LD HH		Fixed		Nymex	08/2012	90000	
32	DEUTSCH	7909	Swap	Nymex LD HH		Fixed		Nymex	08/2012	90000	
33	SUISSE	7910	Swap	Nymex LD HH		Fixed		Nymex	08/2012	80000	
34	**TOTAL**										**$ 2,886,418**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	SHELL	2213				Nymex LD HH		Nymex	09/2012	20000	
2	SHELL	2213	Option (Collar)			Nymex LD HH	Call Price Buy Down		09/2012	20000	
3	SHELL	2214				Nymex LD HH		Nymex	09/2012	20000	
4	JPMORG	2234	Option (Collar)			Nymex LD HH		Nymex	09/2012	20000	
5	JPMORG	2235				Nymex LD HH		Nymex	09/2012	20000	
6	JPMORG	2245	Option (Collar)			Nymex LD HH		Nymex	09/2012	20000	
7	JPMORG	2246				Nymex LD HH		Nymex	09/2012	20000	
8	BBVA	2257	Option (Collar)			Nymex LD HH		Nymex	09/2012	40000	
9	BBVA	2258				Nymex LD HH		Nymex	09/2012	40000	
10	CIBC	2285	Option (Collar)			Nymex LD HH		Nymex	09/2012	20000	
11	CIBC	2286				Nymex LD HH		Nymex	09/2012	20000	
12	JPMORG	2344	Option (Collar)			Nymex LD HH		Nymex	09/2012	30000	
13	JPMORG	2345				Nymex LD HH		Nymex	09/2012	30000	
14	SHELL	2353	Option (Collar)			Nymex LD HH		Nymex	09/2012	30000	
15	SHELL	2354				Nymex LD HH		Nymex	09/2012	30000	
16	JPMORG	2358	Option (Collar)			Nymex LD HH		Nymex	09/2012	30000	
17	JPMORG	2359				Nymex LD HH		Nymex	09/2012	30000	
18	BMO	2368	Option (Collar)			Nymex LD HH		Nymex	09/2012	20000	
19	BMO	2369				Nymex LD HH		Nymex	09/2012	20000	
20	BMO	2585	Option (Collar)			Nymex LD HH		Nymex	09/2012	40000	
21	BMO	2586				Nymex LD HH		Nymex	09/2012	40000	
22	JPMORG	1069	Swap	Fixed		Nymex LD HH		Nymex	09/2012	50000	
23	SUISSE	1091	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
24	SUISSE	1111	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
25	JPMORG	1222	Swap	Fixed		Nymex LD HH		Nymex	09/2012	10000	
26	MERRIL	5154	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
27	DEUTSCH	5204	Swap	Fixed		Nymex LD HH		Nymex	09/2012	10000	
28	SUISSE	5602	Swap	Fixed		Nymex LD HH		Nymex	09/2012	10000	
29	SUISSE	5889	Swap	Fixed		Nymex LD HH		Nymex	09/2012	10000	
30	JPMORG	5934	Swap	Fixed		Nymex LD HH		Nymex	09/2012	80000	
31	JPMORG	5976	Swap	Fixed		Nymex LD HH		Nymex	09/2012	50000	
32	SHELL	5981	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
33	JPMORG	5982	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
34	JPMORG	6064	Swap	Fixed		Nymex LD HH		Nymex	09/2012	110000	
35	SUISSE	6099	Swap	Fixed		Nymex LD HH		Nymex	09/2012	50000	
36	JPMORG	6177	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
37	SHELL	6197	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
38	CITIGR	6206	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
39	BARCLAY	6229	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
40	JPMORG	6235	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
41	SHELL	6271	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
42	CITIGR	6291	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
43	JPMORG	6374	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
44	BBVA	6401	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
45	BBVA	6451	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
46	CITIGR	6482	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
47	CITIGR	6592	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
48	JPMORG	6607	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
49	CIBC	6648	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
50	JPMORG	6737	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
51	MERRIL	6754	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
52	JPMORG	7084	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
53	CIBC	7088	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
54	JPMORG	7098	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
55	JPMORG	7107	Swap	Fixed		Nymex LD HH		Nymex	09/2012	50000	
56	BARCLAY	7119	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
57	CIBC	7127	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
58	MORGAN	7136	Swap	Fixed		Nymex LD HH		Nymex	09/2012	20000	
59	CIBC	7143	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
60	FIFTH	7168	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
61	CIBC	7182	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
62	JPMORG	7196	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
63	CIBC	7205	Swap	Fixed		Nymex LD HH		Nymex	09/2012	30000	
64	FIFTH	7359	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
65	BMO	7377	Swap	Fixed		Nymex LD HH		Nymex	09/2012	50000	
66	BMO	7386	Swap	Fixed		Nymex LD HH		Nymex	09/2012	50000	
67	BMO	7434	Swap	Fixed		Nymex LD HH		Nymex	09/2012	40000	
68	SHELL	7884	Swap	Nymex LD HH		GD HH		Gas Daily	09/2012	300000	
69	DEUTSCH	7886	Swap	Nymex LD HH		GD HH		Gas Daily	09/2012	300000	
70	SHELL	7901	Swap	Nymex LD HH		GD HH		Gas Daily	09/2012	300000	
71	SHELL	7912	Swap	Nymex LD HH		GD HH		Gas Daily	09/2012	300000	
72	DEUTSCH	7917	Swap	Nymex LD HH		GD HH		Gas Daily	09/2012	300000	
73	CITIGR	7918	Swap	Nymex LD HH		GD HH		Gas Daily	09/2012	60000	
74	**TOTAL**										**$ 2,922,638**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	SHELL	2213	Option (Collar)			Nymex LD HH		Nymex	10/2012	20000	
2	SHELL	2213				Nymex LD HH	Call Price Buy Down		10/2012	20000	
3	SHELL	2214				Nymex LD HH		Nymex	10/2012	20000	
4	JPMORG	2234	Option (Collar)			Nymex LD HH		Nymex	10/2012	20000	
5	JPMORG	2235				Nymex LD HH		Nymex	10/2012	20000	
6	JPMORG	2245	Option (Collar)			Nymex LD HH		Nymex	10/2012	20000	
7	JPMORG	2246				Nymex LD HH		Nymex	10/2012	20000	
8	BBVA	2257	Option (Collar)			Nymex LD HH		Nymex	10/2012	40000	
9	BBVA	2258				Nymex LD HH		Nymex	10/2012	40000	
10	CIBC	2285	Option (Collar)			Nymex LD HH		Nymex	10/2012	20000	
11	CIBC	2286				Nymex LD HH		Nymex	10/2012	20000	
12	JPMORG	2344	Option (Collar)			Nymex LD HH		Nymex	10/2012	30000	
13	JPMORG	2345				Nymex LD HH		Nymex	10/2012	30000	
14	SHELL	2353	Option (Collar)			Nymex LD HH		Nymex	10/2012	30000	
15	SHELL	2354				Nymex LD HH		Nymex	10/2012	30000	
16	JPMORG	2358	Option (Collar)			Nymex LD HH		Nymex	10/2012	30000	
17	JPMORG	2359				Nymex LD HH		Nymex	10/2012	30000	
18	BMO	2368	Option (Collar)			Nymex LD HH		Nymex	10/2012	20000	
19	BMO	2369				Nymex LD HH		Nymex	10/2012	20000	
20	CITIGR	2648	Option (Collar)			Nymex LD HH		Nymex	10/2012	120000	
21	CITIGR	2649				Nymex LD HH		Nymex	10/2012	120000	
22	JPMORG	1069	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
23	SUISSE	1091	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
24	SUISSE	1111	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
25	JPMORG	1222	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
26	MERRIL	5154	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
27	DEUTSCH	5204	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
28	SUISSE	5602	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
29	SUISSE	5889	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
30	JPMORG	5934	Swap	Fixed		Nymex LD HH		Nymex	10/2012	80000	
31	JPMORG	5976	Swap	Fixed		Nymex LD HH		Nymex	10/2012	50000	
32	SHELL	5981	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
33	JPMORG	5982	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
34	JPMORG	6064	Swap	Fixed		Nymex LD HH		Nymex	10/2012	110000	
35	SUISSE	6099	Swap	Fixed		Nymex LD HH		Nymex	10/2012	50000	
36	JPMORG	6177	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
37	SHELL	6197	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
38	CITIGR	6206	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
39	BARCLAY	6229	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
40	JPMORG	6235	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
41	SHELL	6271	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
42	CITIGR	6291	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
43	JPMORG	6374	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
44	BBVA	6401	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
45	BBVA	6451	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
46	CITIGR	6482	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
47	CITIGR	6592	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
48	JPMORG	6607	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
49	CIBC	6648	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
50	JPMORG	6737	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
51	MERRIL	6754	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
52	JPMORG	7084	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
53	CIBC	7088	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
54	JPMORG	7098	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
55	JPMORG	7107	Swap	Fixed		Nymex LD HH		Nymex	10/2012	50000	
56	BARCLAY	7119	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
57	CIBC	7127	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
58	MORGAN	7136	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
59	CIBC	7143	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
60	FIFTH	7168	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
61	CIBC	7182	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
62	JPMORG	7196	Swap	Fixed		Nymex LD HH		Nymex	10/2012	40000	
63	CIBC	7205	Swap	Fixed		Nymex LD HH		Nymex	10/2012	30000	
64	FIFTH	7359	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
65	BMO	7377	Swap	Fixed		Nymex LD HH		Nymex	10/2012	20000	
66	BMO	7386	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
67	BMO	7434	Swap	Fixed		Nymex LD HH		Nymex	10/2012	10000	
68	SHELL	7966	Swap	Nymex LD HH		GD HH		Gas Daily	10/2012	620000	
69	DEUTSCH	7967	Swap	Nymex LD HH		GD HH		Gas Daily	10/2012	310000	
70	JPMORG	7968	Swap	Nymex LD HH		GD HH		Gas Daily	10/2012	310000	
71	JPMORG	7969	Swap	Nymex LD HH		GD HH		Gas Daily	10/2012	120000	
72	**TOTAL**										**$ 1,891,416**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	SHELL	2213	Option (Collar)			Nymex LD HH		Nymex	11/2012	20000	
2	SHELL	2213				Nymex LD HH	Call Price Buy Down		11/2012	20000	
3	SHELL	2214				Nymex LD HH		Nymex	11/2012	20000	
4	JPMORG	2234	Option (Collar)			Nymex LD HH		Nymex	11/2012	20000	
5	JPMORG	2235				Nymex LD HH		Nymex	11/2012	20000	
6	JPMORG	2245	Option (Collar)			Nymex LD HH		Nymex	11/2012	20000	
7	JPMORG	2246				Nymex LD HH		Nymex	11/2012	20000	
8	BBVA	2257	Option (Collar)			Nymex LD HH		Nymex	11/2012	40000	
9	BBVA	2258				Nymex LD HH		Nymex	11/2012	40000	
10	CIBC	2285	Option (Collar)			Nymex LD HH		Nymex	11/2012	20000	
11	CIBC	2286				Nymex LD HH		Nymex	11/2012	20000	
12	JPMORG	2344	Option (Collar)			Nymex LD HH		Nymex	11/2012	30000	
13	JPMORG	2345				Nymex LD HH		Nymex	11/2012	30000	
14	SHELL	2353	Option (Collar)			Nymex LD HH		Nymex	11/2012	30000	
15	SHELL	2354				Nymex LD HH		Nymex	11/2012	30000	
16	JPMORG	2358	Option (Collar)			Nymex LD HH		Nymex	11/2012	30000	
17	JPMORG	2359				Nymex LD HH		Nymex	11/2012	30000	
18	BMO	2368	Option (Collar)			Nymex LD HH		Nymex	11/2012	20000	
19	BMO	2369				Nymex LD HH		Nymex	11/2012	20000	
20	SCOTIA	2675	Option (Collar)			Nymex LD HH		Nymex	11/2012	120000	
21	SCOTIA	2676				Nymex LD HH		Nymex	11/2012	120000	
22	JPMORG	1069	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
23	SUISSE	1091	Swap	Fixed		Nymex LD HH		Nymex	11/2012	10000	
24	SUISSE	1111	Swap	Fixed		Nymex LD HH		Nymex	11/2012	10000	
25	JPMORG	5934	Swap	Fixed		Nymex LD HH		Nymex	11/2012	80000	
26	JPMORG	5976	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
27	SHELL	5981	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
28	JPMORG	5982	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
29	JPMORG	6064	Swap	Fixed		Nymex LD HH		Nymex	11/2012	110000	
30	SUISSE	6099	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
31	JPMORG	6177	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
32	SHELL	6197	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
33	CITIGR	6206	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
34	BARCLAY	6229	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
35	JPMORG	6235	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
36	SHELL	6271	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
37	CITIGR	6291	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
38	JPMORG	6374	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
39	BBVA	6401	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
40	BBVA	6451	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
41	CITIGR	6482	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
42	CITIGR	6592	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
43	JPMORG	6607	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
44	CIBC	6648	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
45	JPMORG	6737	Swap	Fixed		Nymex LD HH		Nymex	11/2012	40000	
46	MERRIL	6754	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
47	JPMORG	7084	Swap	Fixed		Nymex LD HH		Nymex	11/2012	30000	
48	CIBC	7205	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
49	FIFTH	7359	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
50	BMO	7377	Swap	Fixed		Nymex LD HH		Nymex	11/2012	20000	
51	BMO	7386	Swap	Fixed		Nymex LD HH		Nymex	11/2012	10000	
52	BMO	7434	Swap	Fixed		Nymex LD HH		Nymex	11/2012	10000	
53	MERRIL	7759	Swap	Fixed		Nymex LD HH		Nymex	11/2012	40000	
54	DEUTSCH	7787	Swap	Fixed		Nymex LD HH		Nymex	11/2012	40000	
55	BMO	7804	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
56	JPMORG	7812	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
57	MERRIL	7830	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
58	MERRIL	7837	Swap	Fixed		Nymex LD HH		Nymex	11/2012	80000	
59	SCOTIA	7860	Swap	Fixed		Nymex LD HH		Nymex	11/2012	40000	
60	FIFTH	7866	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
61	CIBC	7889	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
62	JPMORG	7902	Swap	Fixed		Nymex LD HH		Nymex	11/2012	50000	
63	JPMORG	7933	Swap	Fixed		Nymex LD HH		Nymex	11/2012	70000	
64	BMO	7952	Swap	Fixed		Nymex LD HH		Nymex	11/2012	70000	
65	FIFTH	7958	Swap	Fixed		Nymex LD HH		Nymex	11/2012	70000	
66	JPMORG	8000	Swap	Fixed		Nymex LD HH		Nymex	11/2012	200000	
67	CITIGR	8011	Swap	Fixed		Nymex LD HH		Nymex	11/2012	250000	
68	CIBC	8013	Swap	Fixed		Nymex LD HH		Nymex	11/2012	250000	
69	SHELL	8015	Swap	Nymex LD HH		GD HH		Gas Daily	11/2012	300000	
70	MERRIL	8016	Swap	Nymex LD HH		GD HH		Gas Daily	11/2012	300000	
71	SUISSE	8017	Swap	Fixed		Nymex LD HH		Nymex	11/2012	120000	
72	CITIGR	8018	Swap	Nymex LD HH		GD HH		Gas Daily	11/2012	600000	
73	SHELL	8021	Swap	Nymex LD HH		GD HH		Gas Daily	11/2012	300000	
74	SHELL	8022	Swap	Nymex LD HH		GD HH		Gas Daily	11/2012	50000	
75	DEUTSCH	8023	Swap	Nymex LD HH		GD HH		Gas Daily	11/2012	900000	
76	**TOTAL**										**$ 1,268,335**

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	SHELL	2213	Option (Collar)			Nymex LD HH		Nymex	12/2012	20000	
2	SHELL	2213				Nymex LD HH	Call Price Buy Down		12/2012	20000	
3	SHELL	2214				Nymex LD HH		Nymex	12/2012	20000	
4	JPMORG	2234	Option (Collar)			Nymex LD HH		Nymex	12/2012	20000	
5	JPMORG	2235				Nymex LD HH		Nymex	12/2012	20000	
6	JPMORG	2245	Option (Collar)			Nymex LD HH		Nymex	12/2012	20000	
7	JPMORG	2246				Nymex LD HH		Nymex	12/2012	20000	
8	BBVA	2257	Option (Collar)			Nymex LD HH		Nymex	12/2012	40000	
9	BBVA	2258				Nymex LD HH		Nymex	12/2012	40000	
10	CIBC	2285	Option (Collar)			Nymex LD HH		Nymex	12/2012	20000	
11	CIBC	2286				Nymex LD HH		Nymex	12/2012	20000	
12	JPMORG	2344	Option (Collar)			Nymex LD HH		Nymex	12/2012	30000	
13	JPMORG	2345				Nymex LD HH		Nymex	12/2012	30000	
14	SHELL	2353	Option (Collar)			Nymex LD HH		Nymex	12/2012	30000	
15	SHELL	2354				Nymex LD HH		Nymex	12/2012	30000	
16	JPMORG	2358	Option (Collar)			Nymex LD HH		Nymex	12/2012	30000	
17	JPMORG	2359				Nymex LD HH		Nymex	12/2012	30000	
18	BMO	2368	Option (Collar)			Nymex LD HH		Nymex	12/2012	20000	
19	BMO	2369				Nymex LD HH		Nymex	12/2012	20000	
20	CIBC	2709	Option (Collar)			Nymex LD HH		Nymex	12/2012	60000	
21	CIBC	2710				Nymex LD HH		Nymex	12/2012	60000	
22	FIFTH	2711	Option (Collar)			Nymex LD HH		Nymex	12/2012	60000	
23	FIFTH	2712				Nymex LD HH		Nymex	12/2012	60000	
24	JPMORG	1069	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
25	SUISSE	1091	Swap	Fixed		Nymex LD HH		Nymex	12/2012	10000	
26	SUISSE	1111	Swap	Fixed		Nymex LD HH		Nymex	12/2012	10000	
27	JPMORG	5934	Swap	Fixed		Nymex LD HH		Nymex	12/2012	80000	
28	JPMORG	5976	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
29	SHELL	5981	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
30	JPMORG	5982	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
31	JPMORG	6064	Swap	Fixed		Nymex LD HH		Nymex	12/2012	110000	
32	SUISSE	6099	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
33	JPMORG	6177	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
34	SHELL	6197	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
35	CITIGR	6206	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
36	BARCLAY	6229	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
37	JPMORG	6235	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
38	SHELL	6271	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
39	CITIGR	6291	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
40	JPMORG	6374	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
41	BBVA	6401	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
42	BBVA	6451	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
43	CITIGR	6482	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
44	CITIGR	6592	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
45	JPMORG	6607	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
46	CIBC	6648	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
47	JPMORG	6737	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
48	MERRIL	6754	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
49	JPMORG	7084	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
50	CIBC	7088	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
51	JPMORG	7098	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
52	JPMORG	7107	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
53	BARCLAY	7119	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
54	CIBC	7127	Swap	Fixed		Nymex LD HH		Nymex	12/2012	30000	
55	MORGAN	7136	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
56	CIBC	7143	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
57	FIFTH	7168	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
58	CIBC	7182	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
59	JPMORG	7196	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
60	CIBC	7205	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
61	FIFTH	7359	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
62	BMO	7377	Swap	Fixed		Nymex LD HH		Nymex	12/2012	20000	
63	BMO	7386	Swap	Fixed		Nymex LD HH		Nymex	12/2012	10000	
64	BMO	7434	Swap	Fixed		Nymex LD HH		Nymex	12/2012	10000	
65	MERRIL	7759	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
66	DEUTSCH	7787	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
67	BMO	7804	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
68	JPMORG	7812	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
69	MERRIL	7830	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
70	MERRIL	7837	Swap	Fixed		Nymex LD HH		Nymex	12/2012	80000	
71	SCOTIA	7860	Swap	Fixed		Nymex LD HH		Nymex	12/2012	40000	
72	FIFTH	7866	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
73	CIBC	7889	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
74	JPMORG	7902	Swap	Fixed		Nymex LD HH		Nymex	12/2012	50000	
75	JPMORG	7933	Swap	Fixed		Nymex LD HH		Nymex	12/2012	120000	
76	BMO	7952	Swap	Fixed		Nymex LD HH		Nymex	12/2012	120000	
77	FIFTH	7958	Swap	Fixed		Nymex LD HH		Nymex	12/2012	120000	
78	JPMORG	8000	Swap	Fixed		Nymex LD HH		Nymex	12/2012	200000	

	A	B	C	D	E	F	G	H	I	J	K
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Hedge Month	Volume	Dollar Amount
1	CITIGR	8011	Swap	Fixed		Nymex LD HH		Nymex	12/2012	200000	
2	CIBC	8013	Swap	Fixed		Nymex LD HH		Nymex	12/2012	200000	
3	SUISSE	8017	Swap	Fixed		Nymex LD HH		Nymex	12/2012	120000	
4	CITIGR	8031	Swap	Fixed		Nymex LD HH		Nymex	12/2012	200000	
5	MERRIL	8037	Swap	Fixed		Nymex LD HH		Nymex	12/2012	80000	
6	SCOTIA	8070	Swap	Fixed		Nymex LD HH		Nymex	12/2012	60000	
7	SUISSE	8090	Swap	Nymex LD HH		GD HH		Gas Daily	12/2012	310000	
8	DEUTSCH	8091	Swap	Nymex LD HH		GD HH		Gas Daily	12/2012	310000	
9	MERRIL	8092	Swap	Nymex LD HH		Fixed		Nymex	12/2012	490000	
10	MERRIL	8093	Swap	Fixed		Nymex LD HH		Nymex	12/2012	490000	
11	CIBC	8096	Swap	Fixed		Nymex LD HH		Nymex	12/2012	80000	
12	BMO	8100	Swap	Nymex LD HH		Fixed		Nymex	12/2012	490000	
13	BMO	8101	Swap	Fixed		Nymex LD HH		Nymex	12/2012	490000	
14	SUISSE	8102	Swap	Nymex LD HH		Fixed		Nymex	12/2012	530000	
15	SUISSE	8103	Swap	Fixed		Nymex LD HH		Nymex	12/2012	530000	
16	SHELL	8105	Swap	Fixed		Nymex LD HH		Nymex	12/2012	70000	
17	CITIGR	8108	Swap	Nymex LD HH		GD HH		Gas Daily	12/2012	310000	
18	JPMORG	8109	Swap	Nymex LD HH		GD HH		Gas Daily	12/2012	620000	
19	CITIGR	8110	Swap	Nymex LD HH		GD HH		Gas Daily	12/2012	220000	
20	MERRIL	8119	Swap	Nymex LD HH		Fixed		Nymex	12/2012	160000	
21	FIFTH	8126	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
22	DEUTSCH	8127	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
23	SUISSE	8131	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
24	FIFTH	8132	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
25	SHELL	8133	Swap	Nymex LD HH		Fixed		Nymex	12/2012	180000	
26	SCOTIA	8135	Swap	Nymex LD HH		Fixed		Nymex	12/2012	50000	
27	MORGAN	8147	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
28	FIFTH	8150	Swap	Nymex LD HH		Fixed		Nymex	12/2012	50000	
29	DEUTSCH	8163	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
30	CIBC	8165	Swap	Nymex LD HH		Fixed		Nymex	12/2012	150000	
31	SCOTIA	8166	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
32	DEUTSCH	8168	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
33	CITIGR	8170	Swap	Nymex LD HH		Fixed		Nymex	12/2012	60000	
34	BARCLAY	8172	Swap	Nymex LD HH		Fixed		Nymex	12/2012	50000	
35	SUISSE	8173	Swap	Nymex LD HH		Fixed		Nymex	12/2012	280000	
36	CIBC	8177	Swap	Nymex LD HH		Fixed		Nymex	12/2012	30000	
37	SCOTIA	8186	Swap	Nymex LD HH		Fixed		Nymex	12/2012	20000	
38	**TOTAL**										**$ 1,965,204**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 38,020
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 40,220
3	BARCLAY	7217	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 30,780
4	BARCLAY	7693	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 2,440
5	BARCLAY	8187	Swap	Nymex LD HH		Fixed		Nymex	$ 3.3540	01/2013		$ 10,540
6	BARCLAY	8188	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	01/2013		$ 41,540
7	BARCLAY	8200	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (4,320)
8	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 51,480
9	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 51,360
10	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 44,670
11	BMO	7804	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 14,160
12	BMO	8178	Swap	Nymex LD HH		Fixed		Nymex	$ 3.3540	01/2013		$ (1,800)
13	BMO	8179	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	01/2013		$ 52,950
14	BMO	8215	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ 5,340
15	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 2,580
16	BNPP ET	7736	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 6,030
17	BNPP ET	8189	Swap	Nymex LD HH		Fixed		Nymex	$ 3.3540	01/2013		$ (310)
18	BNPP ET	8190	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	01/2013		$ 53,165
19	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 57,930
20	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 1,550
21	BP	8122	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 14,760
22	BP	8128	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 7,840
23	BP	8221	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (109,600)
24	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 48,480
25	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 64,440
26	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 9,030
27	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 7,520
28	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 5,720
29	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 1,320
30	CIBC	7576	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (2,070)
31	CIBC	7702	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 1,040
32	CIBC	7889	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (4,565)
33	CIBC	8013	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 13,300
34	CIBC	8096	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 8,720
35	CIBC	8216	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (5,940)
36	CIBC	8225	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (25,080)
37	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 113,050
38	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 35,620
39	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 31,220
40	CITIGR	7240	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 25,980
41	CITIGR	7307	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 20,880
42	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 8,580
43	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 11,280
44	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 17,600
45	CITIGR	8011	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 54,900
46	CITIGR	8031	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 62,400
47	CITIGR	8184	Swap	Nymex LD HH		Fixed		Nymex	$ 3.3540	01/2013		$ (4,800)
48	CITIGR	8185	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	01/2013		$ 55,200
49	CITIGR	8191	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (18,000)
50	DEUTSCH	7751	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 8,580
51	DEUTSCH	7787	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 7,300
52	DEUTSCH	8201	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (6,840)
53	DEUTSCH	8218	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (7,740)
54	DEUTSCH	8222	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (11,760)
55	DEUTSCH	8226	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (2,370)
56	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 34,720
57	FIFTH	7680	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (3,360)
58	FIFTH	7866	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (3,190)
59	FIFTH	8202	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ 660
60	FIFTH	8223	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (12,360)
61	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 70,520
62	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 68,820
63	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 80,640
64	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 32,320
65	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 57,240
66	JPMORG	7113	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 22,420
67	JPMORG	7120	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 42,040
68	JPMORG	7129	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 20,820
69	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 1,220
70	JPMORG	7563	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 420
71	JPMORG	7812	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 8,760
72	JPMORG	7902	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (6,480)
73	JPMORG	8000	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 109,200
74	JPMORG	8180	Swap	Nymex LD HH		Fixed		Nymex	$ 3.3540	01/2013		$ (1,200)
75	JPMORG	8181	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	01/2013		$ 35,300

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
76	MERRIL	7087	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	$ 3.3540	01/2013	[redacted]	$ 34,680
77	MERRIL	7759	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 2,160
78	MERRIL	7830	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (1,520)
79	MERRIL	7837	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 3,600
80	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 6,300
81	MERRIL	8037	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 33,600
82	MERRIL	8176	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.3382	01/2013		$ 9,796
83	MORGAN	8182	Swap	Nymex LD HH		Fixed		Nymex	$ 3.3540	01/2013		$ (8,400)
84	MORGAN	8183	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	01/2013		$ 76,600
85	MORGAN	8198	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ 3,360
86	MORGAN	8220	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (25,400)
87	SCOTIA	7860	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ (280)
88	SCOTIA	8070	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 15,060
89	SCOTIA	8117	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 15,425
90	SCOTIA	8195	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ 510
91	SCOTIA	8207	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ 5,160
92	SCOTIA	8219	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (12,540)
93	SCOTIA	8224	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (13,160)
94	SCOTIA	8236	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ 30
95	SHELL	6443	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 59,580
96	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 37,520
97	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 52,080
98	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 13,410
99	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 12,810
100	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 6,630
101	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 2,120
102	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 1,830
103	SHELL	8175	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.3407	01/2013		$ 12,369
104	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 71,920
105	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 35,120
106	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 37,920
107	SUISSE	8017	Swap	Fixed		Nymex LD HH		Nymex	$ 3.3540	01/2013		$ 41,520
108	SUISSE	8217	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	01/2013		$ (9,240)
109	**TOTAL**											**$ 2,013,400**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 40,580
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 42,780
3	BARCLAY	7217	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 34,620
4	BARCLAY	7693	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 3,780
5	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 55,320
6	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 55,200
7	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 48,510
8	BMO	7804	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 21,840
9	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 6,420
10	BNPP ET	7736	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 6,580
11	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 61,770
12	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 7,950
13	BP	8122	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 22,440
14	BP	8128	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 12,960
15	BP	8259	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 27,090
16	BP	8279	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 32,760
18	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 52,320
19	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 69,560
20	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 12,870
21	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 10,080
17	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 8,280
22	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 3,880
23	CIBC	7576	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 1,180
24	CIBC	7702	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 3,080
25	CIBC	7889	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 6,920
26	CIBC	8013	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 19,700
27	CIBC	8096	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 11,280
28	CIBC	8243	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	02/2013		$ (6,020)
29	CIBC	8244	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	02/2013		$ (67,510)
30	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 119,450
31	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 38,180
32	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 33,780
33	CITIGR	7240	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 29,820
34	CITIGR	7307	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 24,720
35	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 12,420
36	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 15,120
37	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 30,400
38	CITIGR	8011	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 74,100
39	CITIGR	8031	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 81,600
40	CITIGR	8241	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	02/2013		$ (8,170)
41	CITIGR	8242	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	02/2013		$ (67,510)
42	CITIGR	8263	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 10,200
43	DEUTSCH	7751	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 8,280
44	DEUTSCH	7787	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 13,700
45	DEUTSCH	8228	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	02/2013		$ (35,260)
46	DEUTSCH	8229	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	02/2013		$ (46,870)
47	DEUTSCH	8249	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 14,560
48	DEUTSCH	8255	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 160
49	DEUTSCH	8273	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 11,220
50	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 37,280
51	FIFTH	7680	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 440
52	FIFTH	7866	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 7,920
53	FIFTH	8235	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	02/2013		$ (3,960)
54	FIFTH	8269	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 59,280
55	FIFTH	8282	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 1,560
56	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 73,080
57	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 71,380
58	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 85,760
59	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 34,880
60	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 62,360
61	JPMORG	7113	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 24,980
62	JPMORG	7120	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 47,160
63	JPMORG	7129	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 23,380
64	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 3,780
65	JPMORG	7563	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 2,980
66	JPMORG	7812	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 16,440
67	JPMORG	7902	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 5,920
68	JPMORG	8000	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 134,800
69	JPMORG	8257	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 960
70	JPMORG	8262	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 7,850
71	JPMORG	8230	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.2988	02/2013		$ (20,384)
72	MERRIL	7087	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 38,520
73	MERRIL	7759	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 8,200
74	MERRIL	7830	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 6,540
75	MERRIL	7837	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 14,760

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
76	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 12,700
77	MERRIL	8037	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 46,400
78	MORGAN	8245	Swap	Nymex LD HH		Fixed		Nymex	$ 3.2260	02/2013		$ (12,180)
79	MORGAN	8246	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	02/2013		$ (61,740)
80	MORGAN	8253	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 8,560
81	SCOTIA	7860	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 6,200
82	SCOTIA	8070	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 22,740
83	SCOTIA	8117	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 21,825
84	SCOTIA	8254	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 8,160
85	SCOTIA	8264	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 8,100
86	SCOTIA	8276	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 10,920
87	SCOTIA	8284	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 735
88	SHELL	6443	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 63,420
89	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 40,080
90	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 55,920
91	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 14,690
92	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 14,090
93	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 10,470
94	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 4,680
95	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 5,670
96	SHELL	8227	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.2988	02/2013		$ (61,152)
97	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 74,480
98	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 37,680
99	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 40,480
100	SUISSE	8017	Swap	Fixed		Nymex LD HH		Nymex	$ 3.2260	02/2013		$ 56,880
101	SUISSE	8252	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 20,880
102	SUISSE	8260	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 14,840
103	SUISSE	8275	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	02/2013		$ 9,420
104	SUISSE	8232	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.2988	02/2013		$ (15,288)
105	SUISSE	8237	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.2973	02/2013		$ (4,991)
106	**TOTAL**											**$ 2,166,655**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 36,560
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 38,760
3	BARCLAY	7217	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 28,590
4	BARCLAY	7693	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (240)
5	BARCLAY	8285	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	03/2013		$ 2,590
6	BARCLAY	8286	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	03/2013		$ (187,220)
7	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 49,290
8	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 49,170
9	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 42,480
10	BMO	7804	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 9,780
11	BMO	8294	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 101,010
12	BNPP	8323	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 1,440
13	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 390
14	BNPP ET	7736	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 2,560
15	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 55,740
16	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (2,100)
16	BP	8302	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 69,480
17	BP	8324	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 1,210
18	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 46,290
19	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 61,520
20	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 6,840
21	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 6,060
22	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 4,260
23	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (140)
24	CIBC	7576	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (4,260)
25	CIBC	7702	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (940)
26	CIBC	7889	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (10,305)
27	CIBC	8289	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	03/2013		$ (1,110)
28	CIBC	8290	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	03/2013		$ (183,520)
29	CIBC	8312	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 13,680
30	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 109,400
31	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 34,160
32	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 29,760
33	CITIGR	7240	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 23,790
34	CITIGR	7307	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 18,690
35	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 6,390
36	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 9,090
37	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 8,240
38	CITIGR	8280	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	03/2013		$ 61,790
39	CITIGR	8281	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	03/2013		$ (246,420)
40	DEUTSCH	7751	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 4,260
41	DEUTSCH	7787	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 3,650
42	DEUTSCH	8287	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	03/2013		$ (1,110)
43	DEUTSCH	8288	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	03/2013		$ (183,520)
44	DEUTSCH	8295	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 29,160
45	DEUTSCH	8310	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 19,560
46	DEUTSCH	8315	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 5,280
47	DEUTSCH	8334	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 10,100
48	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 33,260
49	FIFTH	7680	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (4,710)
50	FIFTH	7866	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (9,180)
51	FIFTH	8301	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 33,950
52	FIFTH	8311	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 14,760
53	FIFTH	8316	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ (560)
54	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 69,060
55	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 67,360
56	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 77,720
57	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 30,860
58	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 54,320
59	JPMORG	7113	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 20,960
60	JPMORG	7120	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 39,120
61	JPMORG	7129	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 19,360
62	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (240)
63	JPMORG	7563	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (1,040)
63	JPMORG	7812	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 4,380
64	JPMORG	7902	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (11,430)
65	JPMORG	8293	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 32,160
66	JPMORG	8314	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 4,980
67	MERRIL	7087	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 32,490
68	MERRIL	7759	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (1,850)
69	MERRIL	7830	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (5,520)
70	MERRIL	7837	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (3,330)
71	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 2,650
72	SCOTIA	7860	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (3,850)
73	SCOTIA	8296	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 25,560
74	SCOTIA	8304	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 21,510
75	SCOTIA	8313	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 3,360

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
76	SHELL	6443	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	$ 3.4270	03/2013	[redacted]	$ 57,390
77	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 36,060
78	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 49,890
79	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 12,680
80	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 12,080
81	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 4,440
82	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 660
83	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ (360)
84	SHELL	8277	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.8064	03/2013		$ (117,614)
85	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 70,460
86	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 33,660
87	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4270	03/2013		$ 36,460
88	SUISSE	8291	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4270	03/2013		$ (1,080)
89	SUISSE	8292	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	03/2013		$ (178,560)
90	SUISSE	8298	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 28,560
91	SUISSE	8303	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	03/2013		$ 22,260
92	**TOTAL**											**$ 793,231**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 25,580
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 27,780
3	BARCLAY	8378	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (2,660)
4	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 32,820
5	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 32,700
6	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 26,010
7	BMO	8036	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (14,480)
8	BNPP	8346	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 7,020
9	BNPP	8371	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (2,860)
10	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (16,080)
11	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 39,270
12	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (29,550)
13	CARGILL	8365	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (2,580)
14	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 29,820
15	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 39,560
16	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (9,630)
17	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (4,920)
18	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (6,720)
19	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (11,120)
20	CIBC	8342	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 3,840
21	CIBC	8364	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 1,940
22	CIBC	8366	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (1,460)
23	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 81,950
24	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 23,180
25	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 18,780
26	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (10,080)
27	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (7,380)
28	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (17,840)
29	CITIGR	8367	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 940
30	DEUTSCH	8327	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	04/2013		$ 660
31	DEUTSCH	8328	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	04/2013		$ (17,820)
32	DEUTSCH	8341	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 3,240
33	DEUTSCH	8359	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 1,040
34	DEUTSCH	8370	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (13,080)
35	DEUTSCH	8379	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (1,860)
36	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 22,280
37	FIFTH	8330	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	04/2013		$ 660
38	FIFTH	8331	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	04/2013		$ (17,270)
39	FIFTH	8337	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 2,040
40	FIFTH	8369	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (580)
41	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 58,080
42	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 56,380
43	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 55,760
44	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 19,880
45	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 32,360
46	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (11,220)
47	JPMORG	8121	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (16,560)
48	JPMORG	8336	Swap	Nymex LD HH		GD HH		Gas Daily	$ 4.1487	04/2013		$ (31,086)
49	MERRIL	7087	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 16,020
50	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (24,800)
51	MITSUI	8344	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 4,640
52	MITSUI	8392	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 240
53	SCOTIA	8356	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 2,290
54	SHELL	6443	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 40,920
55	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 25,080
56	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 33,420
57	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 7,190
58	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 6,590
59	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (12,030)
60	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (10,320)
61	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (16,830)
62	SHELL	8069	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ (20,480)
63	SHELL	8325	Swap	Nymex LD HH		GD HH		Gas Daily	$ 4.1587	04/2013		$ (109,620)
64	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 59,480
65	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 22,680
66	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 3.9760	04/2013		$ 25,480
67	SUISSE	8332	Swap	Nymex LD HH		Fixed		Nymex	$ 3.9760	04/2013		$ 1,860
68	SUISSE	8333	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	04/2013		$ (49,910)
69	SUISSE	8343	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 4,240
70	SUISSE	8350	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ (160)
71	SUISSE	8368	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 40
72	SUISSE	8393	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1520	04/2013		$ 770
73	**TOTAL**											**$ 403,524**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	$ 4.1520	05/2013	[redacted]	$ 22,060
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 24,260
3	BARCLAY	7217	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 6,840
4	BARCLAY	7693	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (14,740)
5	BARCLAY	7843	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (14,760)
6	BARCLAY	8389	Swap	Nymex LD HH		GD HH		Gas Daily	$ 4.0331	05/2013		$ 147,436
7	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 27,540
8	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 27,420
9	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 20,730
10	BMO	7153	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 6,220
11	BMO	7170	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 7,920
12	BMO	7173	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 6,720
13	BMO	7264	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (2,160)
14	BMO	7314	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (5,460)
15	BMO	8036	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (28,560)
16	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (21,360)
17	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 33,990
18	BP	7853	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (15,960)
19	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (38,350)
20	CARGILL	8381	Swap	Nymex LD HH		GD HH		Gas Daily	$ 4.0336	05/2013		$ 36,704
21	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 24,540
22	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 32,520
23	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (14,910)
24	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (8,440)
25	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (10,240)
26	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (14,640)
27	CIBC	7576	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (26,010)
28	CIBC	7702	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (15,440)
29	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 73,150
30	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 19,660
31	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 15,260
32	CITIGR	7240	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 2,040
33	CITIGR	7307	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (3,060)
34	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (15,360)
35	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (12,660)
36	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (24,880)
37	CITIGR	8380	Swap	Nymex LD HH		GD HH		Gas Daily	$ 4.0336	05/2013		$ 36,704
38	CITIGR	8391	Swap	Nymex LD HH		GD HH		Gas Daily	$ 4.0341	05/2013		$ 11,790
39	DEUTSCH	7867	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (35,220)
40	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 18,760
41	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 54,560
42	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 52,860
43	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 48,720
44	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 16,360
45	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 25,320
46	JPMORG	7113	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 9,690
47	JPMORG	7120	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 10,120
48	JPMORG	7129	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 9,720
49	JPMORG	7332	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (11,240)
50	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (14,740)
51	JPMORG	7563	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (15,540)
52	JPMORG	8121	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (27,120)
53	MERRIL	7087	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 10,740
54	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (33,600)
55	SCOTIA	7681	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (27,680)
56	SHELL	6443	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 35,640
57	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 21,560
58	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 28,140
59	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 5,430
60	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 4,830
61	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (17,310)
62	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (13,840)
63	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (22,110)
64	SHELL	8069	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ (34,560)
65	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 55,960
66	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 19,160
67	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1520	05/2013		$ 21,960
68	**TOTAL**											**$ 493,084**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 22,140
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 24,340
3	BARCLAY	7217	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 6,960
4	BARCLAY	7693	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (29,320)
5	BARCLAY	7805	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (24,010)
6	BARCLAY	7817	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (29,960)
7	BARCLAY	7843	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (14,640)
8	BARCLAY	8428	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 18,090
9	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 27,660
10	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 27,540
11	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 20,850
12	BMO	7153	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 6,380
13	BMO	7170	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 12,120
14	BMO	7173	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 10,320
15	BMO	7264	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (2,040)
16	BMO	7314	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (5,340)
17	BMO	8036	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (28,240)
18	BMO	8487	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (16,740)
19	BNPP	8463	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (19,670)
20	BNPP	8472	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	06/2013		$ 14,300
21	BNPP	8476	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (6,300)
22	BNPP	8492	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (38,610)
23	BNPP	3034	Unwind	Fixed		Fixed		Nymex	Deferred	06/2013		$ (1,700)
24	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (21,240)
25	BNPP ET	7736	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (41,510)
26	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 34,110
27	BP	7325	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (11,790)
28	BP	7853	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (15,840)
29	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (38,150)
30	BP	8194	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (23,920)
31	BP	8478	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (2,300)
32	CARGILL	8461	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (19,110)
33	CARGILL	8482	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (11,070)
34	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 24,660
35	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 32,680
36	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (24,650)
37	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (12,540)
38	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (20,320)
39	CIBC	7458	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (20,720)
40	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (14,560)
41	CIBC	7576	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (34,520)
42	CIBC	7626	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (25,680)
43	CIBC	7643	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (15,840)
44	CIBC	7702	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (30,720)
45	CIBC	8206	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (26,320)
46	CIBC	8444	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1480	06/2013		$ 15,120
47	CIBC	8445	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	06/2013		$ 250,020
48	CIBC	8474	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (25,830)
49	CIBC	8501	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (5,040)
50	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 73,350
51	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 19,740
52	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 15,340
53	CITIGR	7240	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 2,160
54	CITIGR	7307	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (2,940)
55	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (25,400)
56	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (20,900)
57	CITIGR	7764	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (36,960)
58	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (24,720)
59	CITIGR	8438	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1480	06/2013		$ (6,970)
60	CITIGR	8439	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	06/2013		$ 208,280
61	CITIGR	8430	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.8325	06/2013		$ 283,950
62	DEUTSCH	7751	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (35,560)
63	DEUTSCH	7867	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (34,980)
64	DEUTSCH	8436	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1480	06/2013		$ (6,970)
65	DEUTSCH	8437	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	06/2013		$ 208,280
66	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 18,840
67	FIFTH	7890	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (43,840)
68	FIFTH	8456	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (59,430)
69	FIFTH	8475	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (10,640)
70	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 54,640
71	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 52,940
72	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 48,880
73	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 16,440
74	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 25,480
75	JPMORG	7113	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 13,080

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
76	JPMORG	7120	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 10,280
77	JPMORG	7129	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 9,880
78	JPMORG	7332	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (22,320)
79	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (14,660)
80	JPMORG	7563	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (38,650)
81	JPMORG	7651	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (14,640)
82	JPMORG	7907	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (24,720)
83	JPMORG	8121	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (26,880)
84	JPMORG	8149	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (24,400)
85	JPMORG	8486	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (22,050)
86	JPMORG	8435	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.8325	06/2013		$ 189,300
87	MERRIL	7087	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 10,860
88	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (33,400)
89	MITSUI	8421	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (11,060)
90	MITSUI	8442	Swap	Nymex LD HH		Fixed		Nymex	$ 4.1480	06/2013		$ 9,720
91	MITSUI	8443	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	06/2013		$ 255,420
92	MITSUI	8479	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (11,400)
93	MITSUI	8503	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ 2,560
94	SCOTIA	7681	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (27,520)
95	SCOTIA	8464	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (14,560)
96	SCOTIA	8477	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (3,800)
97	SCOTIA	8507	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ 4,160
98	SHELL	6443	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 35,760
99	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 21,640
100	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 28,260
101	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 5,470
102	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 4,870
103	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (34,380)
104	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (20,640)
105	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (21,990)
106	SHELL	7662	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (20,040)
107	SHELL	8069	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ (34,240)
108	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 56,040
109	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 19,240
110	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 4.1480	06/2013		$ 22,040
111	SUISSE	8458	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	06/2013		$ 70,750
112	SUISSE	8462	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (20,860)
113	SUISSE	8483	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	06/2013		$ (19,170)
114	**TOTAL**											**$ 916,010**

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
1	BARCLAY	6131	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 30,960
2	BARCLAY	6534	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 33,160
3	BARCLAY	7217	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 20,190
4	BARCLAY	7693	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (11,680)
5	BARCLAY	7805	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 8,820
6	BARCLAY	7817	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 1,170
7	BARCLAY	7843	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (1,410)
8	BARCLAY	8428	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 137,160
9	BARCLAY	8562	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (27,510)
10	BBVA	6657	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 40,890
11	BBVA	6756	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 40,770
12	BBVA	6959	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 34,080
13	BMO	7153	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 24,020
14	BMO	7170	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 38,580
15	BMO	7173	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 36,780
16	BMO	7264	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 11,190
17	BMO	7314	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 7,890
18	BMO	8036	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 7,040
19	BMO	8466	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 19,440
20	BMO	8511	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	07/2013		$ 27,010
21	BMO	8512	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4590	07/2013		$ 175,930
22	BNPP	8513	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	07/2013		$ 30,660
23	BNPP	8514	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4590	07/2013		$ 172,280
24	BNPP	8521	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (10,100)
25	BNPP	8576	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ 4,320
26	BNPP ET	7531	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (8,010)
27	BNPP ET	7736	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (13,680)
28	BP	6402	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 47,340
29	BP	7325	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 1,440
30	BP	7853	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (2,610)
31	BP	7934	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (16,100)
32	BP	8194	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (6,280)
33	BP	8527	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (17,100)
34	BP	8541	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (11,110)
35	BP	8485	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.6195	07/2013		$ 27,125
36	CARGILL	8545	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (23,760)
37	CIBC	6881	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 37,890
38	CIBC	6901	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 50,320
39	CIBC	7400	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (2,600)
40	CIBC	7438	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 690
41	CIBC	7439	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (2,680)
42	CIBC	7458	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (3,080)
43	CIBC	7467	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (5,740)
44	CIBC	7576	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (16,880)
45	CIBC	7626	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 780
46	CIBC	7643	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (2,610)
47	CIBC	7702	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (13,080)
48	CIBC	8206	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (8,680)
49	CIBC	8543	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (18,260)
50	CIBC	8555	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (17,570)
51	CITIGR	5964	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 95,400
52	CITIGR	6646	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 28,560
53	CITIGR	6851	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 24,160
54	CITIGR	7240	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 15,390
55	CITIGR	7307	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 10,290
56	CITIGR	7360	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (3,350)
57	CITIGR	7375	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 1,150
58	CITIGR	7764	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (7,830)
59	CITIGR	7954	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (7,080)
60	DEUTSCH	7751	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (6,030)
61	DEUTSCH	7867	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (8,520)
62	DEUTSCH	8473	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 15,960
63	DEUTSCH	8515	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	07/2013		$ 8,760
64	DEUTSCH	8516	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4590	07/2013		$ 194,180
65	DEUTSCH	8520	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (9,100)
66	DEUTSCH	8528	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (24,200)
67	DEUTSCH	8533	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (21,600)
68	DEUTSCH	8547	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (91,800)
69	FIFTH	6732	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 27,660
70	FIFTH	7890	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (8,560)
71	FIFTH	8498	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 21,250
72	FIFTH	8529	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (43,200)
73	FIFTH	8530	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (26,500)
74	FIFTH	8544	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (16,280)
75	FIFTH	8557	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (15,480)

	A	B	C	D	E	F	G	H	I	J	K	L
	Counterparty	Deal ID.	Settlement Type	We Pay Index	We Pay Price	They Pay Index	They Pay Price	Settlement Source	Settlement Index Price	Hedge Month	Volume	Dollar Amount
76	JPMORG	5287	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 63,460
77	JPMORG	5291	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 61,760
78	JPMORG	6367	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 66,520
79	JPMORG	6765	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 25,260
80	JPMORG	6981	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 43,120
81	JPMORG	7113	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 30,720
82	JPMORG	7120	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 27,920
83	JPMORG	7129	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 27,520
84	JPMORG	7332	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (4,680)
85	JPMORG	7339	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (5,840)
86	JPMORG	7563	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (16,600)
87	JPMORG	7651	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (1,410)
88	JPMORG	7907	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (7,080)
89	JPMORG	8121	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (420)
90	JPMORG	8149	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (2,350)
91	JPMORG	8532	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (24,100)
92	JPMORG	8550	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (22,110)
93	JPMORG	8494	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.6205	07/2013		$ 53,630
94	MERRIL	7087	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 24,090
95	MERRIL	7922	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (11,350)
96	MERRIL	8129	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (960)
97	MERRIL	8459	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 33,360
98	MITSUI	8421	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 19,810
99	SCOTIA	7681	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (9,880)
100	SCOTIA	8509	Swap	Nymex LD HH		Fixed		Nymex	$ 3.7070	07/2013		$ 30,240
101	SCOTIA	8510	Swap	Fixed		Nymex LD HH		Nymex	$ 3.4590	07/2013		$ 169,920
102	SHELL	6443	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 48,990
103	SHELL	6466	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 30,460
104	SHELL	6730	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 41,490
105	SHELL	6998	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 9,880
106	SHELL	7027	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 9,280
107	SHELL	7387	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (7,920)
108	SHELL	7490	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (7,410)
109	SHELL	7555	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (8,760)
110	SHELL	7662	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ (6,810)
111	SHELL	8069	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 1,040
112	SHELL	8540	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (68,970)
113	SUISSE	5200	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 64,860
114	SUISSE	6249	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 28,060
115	SUISSE	6514	Swap	Fixed		Nymex LD HH		Nymex	$ 3.7070	07/2013		$ 30,860
116	SUISSE	8531	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (20,100)
117	SUISSE	8554	Swap	Nymex LD HH		Fixed		Nymex	$ 3.4590	07/2013		$ (29,260)
118	SUISSE	8484	Swap	Nymex LD HH		GD HH		Gas Daily	$ 3.6195	07/2013		$ 27,125
119	**TOTAL**											**$ 1,693,990**

GULF POWER COMPANY

Risk Management Plan
For
Fuel Procurement
Docket No. 130001-EI

Date of Filing: August 2, 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 40
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION H.R. Ball - HRB-5

INDEX

SECTION		PAGES
1	GULF POWER COAL PROCUREMENT STRATEGY	3 - 20
2	GULF POWER COAL TRANSPORTATION STRATEGY	21 - 28
3	GULF POWER NATURAL GAS PROCUREMENT STRATEGY	29 - 33
4	GULF POWER OIL PROCUREMENT STRATEGY	34
5	GULF POWER RISK MANAGEMENT POLICY	35 – 38
6	SOUTHERN COMPANY GENERATION (SCGEN) RISK MANAGEMENT POLICY	39 – 76
7	SCS RISK OVERSIGHT ORGANIZATIONAL CHART	77

GULF POWER LONG-TERM COAL PROCUREMENT STRATEGY AND TACTICAL PLAN FOR 2014

Introduction

Gulf Power (Gulf) reliably serves more than 430,000 customers. During 2012, Gulf generated 9.6 billion kilowatt-hours (kWhs) with $545 million in fuel expense. Coal fired generation represents 50 percent of Gulf's electric generating capacity.

Gulf owns and operates three coal-fired generating plants (Crist, Smith and Scholz) with a combined normal full-load gross rating of 1,469 megawatts (MWs) and annual coal consumption of more than 1.6 million tons.

Gulf also co-owns 50 percent of Plant Daniel, which is operated by Mississippi Power (MPC) and has a projected annual coal consumption of 900,000 tons. The normal full-load capacity of Gulf's ownership at Daniel is 537 MWs.

Competition in the electric utility industry, consolidation in the coal industry, and environmental laws and regulations are just a few of the challenges facing power generators today. As the electric utility industry evolves, a coal procurement strategy must address several issues in order to provide a reliable, cost-competitive, environmentally acceptable fuel supply.

The following is:

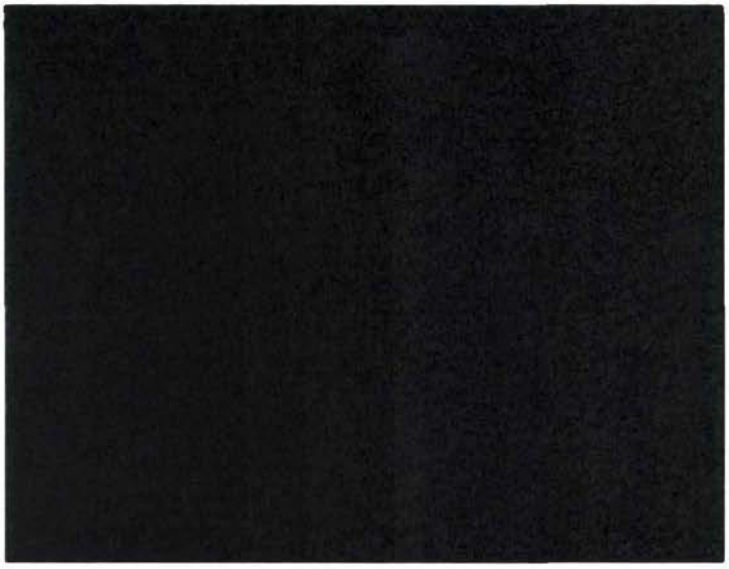
- A review of the current coal program, including current commitments and uncommitted requirements
- A procurement strategy that identifies and addresses specific risks and risk mitigation strategies, and discusses a strategic plan
- A tactical plan detailing specific actions required to achieve the strategy

Fuel Program Overview

Plants Crist and Smith is barge served and plant Scholz is rail served. The following table is a summary of the Gulf coal suppliers and corresponding tonnages (in 1000's) by plant.

Plant	Supplier	2013	2014	2015	2016	2017
Crist & Smith	American					
	Foresight					
	Argus					
	Alpha					
	Total					
Scholz	No suppliers					
Total Gulf Program						

In the following charts, the projected requirements for years 2014 and 2015 are from the July 2013 DEPS burn file and the projected requirements for years 2016 through 2017 are from the 2013 Official Budget June Update. The chart below illustrates the projected burn and commitments of coal for Crist and Smith through 2017.



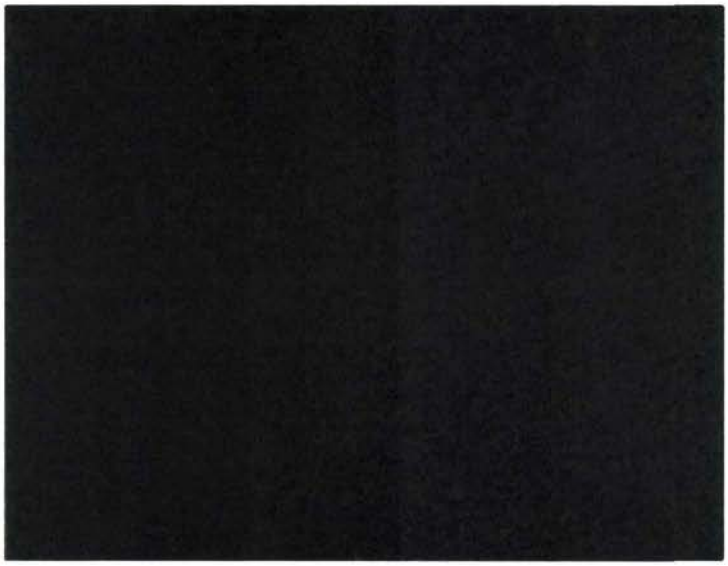
Source: July DEPS (2013-2014)
2013 Energy Budget June Update (2015-2017)

Gulf Power has made the decision to retire the units at Plant Scholz effective April 2015. Scholz will continue to use coal on its stockpile as a generation fuel source until that time. As a result, this strategy will not address future coal needs at Scholz.

Daniel is classified as a New Source Performance Standard (NSPS) plant requiring the use of 1.2 pounds SO_2/MMBtu or less. Gulf owns 50 percent of units 1 and 2 at Daniel, which is rail served. The following table is a summary of the Daniel coal suppliers and corresponding tonnages (in 1000's).

Plant	Supplier	2013	2014	2015	2016	2017
Daniel	Twentymile					
	Total					
Total Daniel Program						

[redacted] The following chart illustrates Gulf's 50 percent ownership in projected burn and commitments of coal for Daniel through 2017.



Source: July DEPS (2013-2014)
2013 Energy Budget June Update (2015-2017)

Procurement Strategy

The long-term coal procurement goal for Gulf is to provide a reliable, cost-competitive, environmentally acceptable coal supply. The successful coal program provides flexibility in volume and pricing, becomes more diverse by pursuing other supply regions, creates competition for supply, focuses on reliability of supply, and adheres to changing environmental laws and guidelines.

In recent years, the coal industry has become more susceptible to the influences of the global commodities market. Given the global market dynamics that occurred during this time frame, the coal market has reacted by becoming more volatile from both a pricing and volume availability standpoint. This has, in turn, impacted the dynamics between natural gas and coal, leading to increased uncertainty in coal burn.

Increased U.S. governmental regulation regarding the potential environmental impact of coal mining will continue to present challenges for coal suppliers seeking permits for new mining activities. This increase in environmental regulation, coupled with the increased regulatory scrutiny of mining safety, has resulted in an increase in production costs and may further lead to a decrease in availability of supply from most domestic regions.

The following section will address the risks and risk mitigation strategies associated with each of these areas. Also included is a discussion of a strategic plan that incorporates several of these mitigation techniques.

Risks and Risk Mitigation Strategies

Volume Risk and Strategy

The uncertainty in the amount of coal generation and therefore coal supply that will be needed in the future remains one of the most critical risks to be addressed in developing a strategy for long-term coal procurement. Weather, economic conditions and natural gas price will continue to impact future coal burn requirements.

Since 2000, Southern Company's natural gas generating capacity has increased by approximately [redacted] to its current size of approximately [redacted] of natural gas generating capacity. This increase in natural gas capacity within the Southern Company system, in conjunction with the recent increased [redacted]

[redacted]

Pricing Risk and Strategy

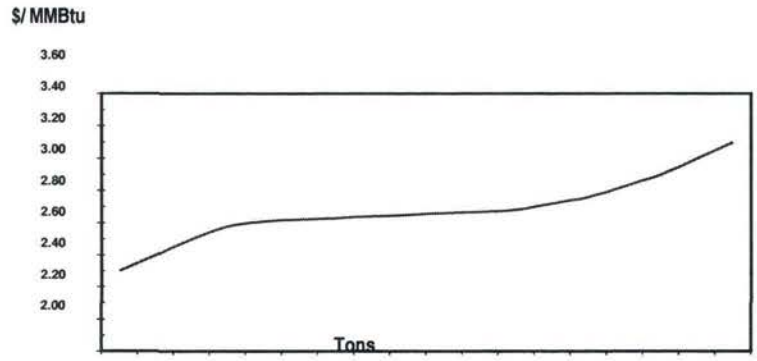
Competing for energy market share with other utilities and power marketers requires competitive energy pricing. Because more than 50 percent of the cost for coal-fired generation is fuel, competitively priced coal supplies should be maintained.

The objective is to have a portfolio of long-term agreements and spot coal purchases that provide pricing at or below market at any given point in time.

[redacted]

Due to the size of our system, the volume of purchases made at a particular time can impact the market. Ranking bid proposals in order of least cost and cumulative volume produces a price curve similar to the following:

Fuel Price Curve



[redacted]

[redacted]

Diversity of Supply Risk and Strategy

There is a risk in relying on one or two large suppliers from a single region to meet supply needs. Also, having the ability to burn coal from various regions will decrease the availability risk associated with lack of supply in a particular region. Diversifying supply will also keep competition strong among suppliers, which, in turn, will continue to foster competitive market prices.

[redacted]

[redacted]

Reliability Risk and Strategy

While reliability is always a risk, when a supply and demand imbalance occurs in the coal industry, this reliability risk is increased. Continuing business with suppliers who have performed well during times of unreliable supply can help mitigate this risk. In addition to an economic evaluation, technical and financial evaluations of suppliers are also performed as a required part of the coal procurement process.

[redacted]

[redacted]

Environmental Risk and Strategy

When procuring coal for a term longer than 12 months, the potential impact from future changes in environmental laws and regulations, which may render the burning of coal as non-economic to our system, is a significant risk that must be mitigated. When executing new long-term coal supply agreements, environmental language will be included that mitigates the risks associated with current, as well as future, environmental issues. This environmental language will continue to allow the company the maximum flexibility and discretion to modify and/or terminate such agreements based on its sole judgment. Environmental language must state clearly that neither coal nor transportation suppliers have the right to review or question our selected environmental compliance strategy.

[redacted]

[redacted]

Strategic Plan

Crist – Crist burns between 900,000 tons and 1.6 million tons of coal a year. All four units at Plant Crist are scrubbed and the plant must comply with a state SO_2 30 day rolling average emission limit of 886 tons of SO_2. Crist has been burning a blend of higher sulfur Illinois Basin coal and lower sulfur coal from the Central Appalachian region. For plant operational reasons the maximum SO_2 content of the blended coal supply has been set at [redacted]. Crist can also burn Colombian import coals, as well as coals from Colorado, Utah and the Central Appalachian regions[redacted]

Smith – Smith burns between 250,000 and 500,000 tons of coal a year and must comply with the state SO_2 emission limit of 2.1 lbs SO_2/MMBtu. Smith can burn a variety of coals, including Illinois Basin and import coals such as Colombian, Australian and Venezuelan. Domestic sources such as Colorado, Utah and Central Appalachian coals also have been burned in the past[redacted]

Daniel – Daniel is served by the Mississippi Export Railroad (MSE) which is approximately 40 miles in length and runs between Moss Point

and Evanston, Miss. The MSE is served by two large Class 1 railroads: the Canadian National Railroad connecting at Evanston and the CSX Railroad connecting at Moss Point. Classified as an NSPS plant, Daniel must use "compliance" coal with a maximum of 1.2 lbs SO_2/MMBtu (0.6 lbs Sulfur/MMBtu). Daniel can burn import coal in addition to coal from Colorado and the Central Appalachian regions. [redacted]

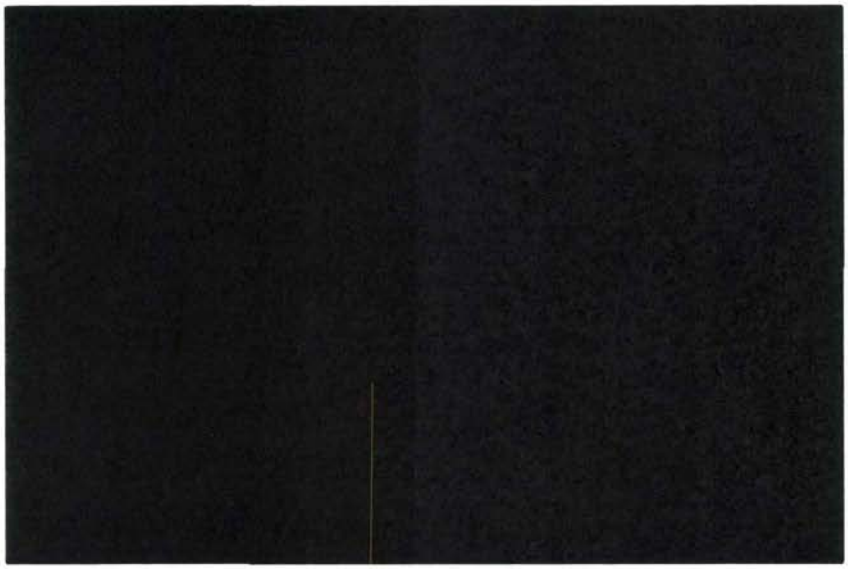
[redacted]

[redacted]

Tactical Plan

Crist and Smith

The chart below shows a breakdown of the current Crist and Smith suppliers and volume commitments, including options, through 2017.

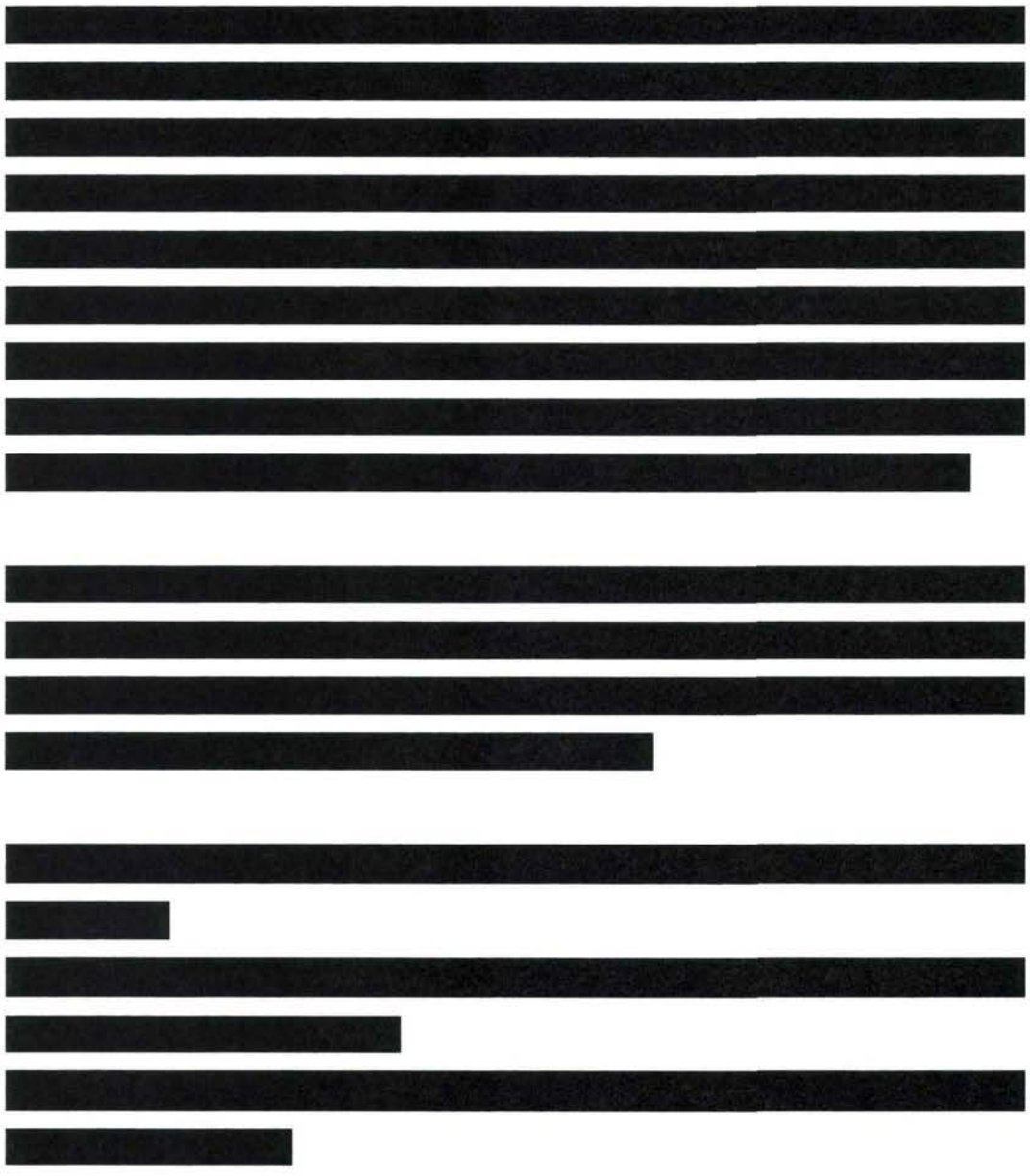


Source: July DEPS (2013-2014)
2013 Energy Budget June Update (2015-2017)

Crist and Smith are projected to burn, on average, approximately 1.7 million tons of coal annually between 2013 and 2017. The committed volume for these plants equates to 100 percent of Crist and Smith's collective need in 2013. [redacted] This tactical plan will address Gulf's requirements for 2013 and beyond.

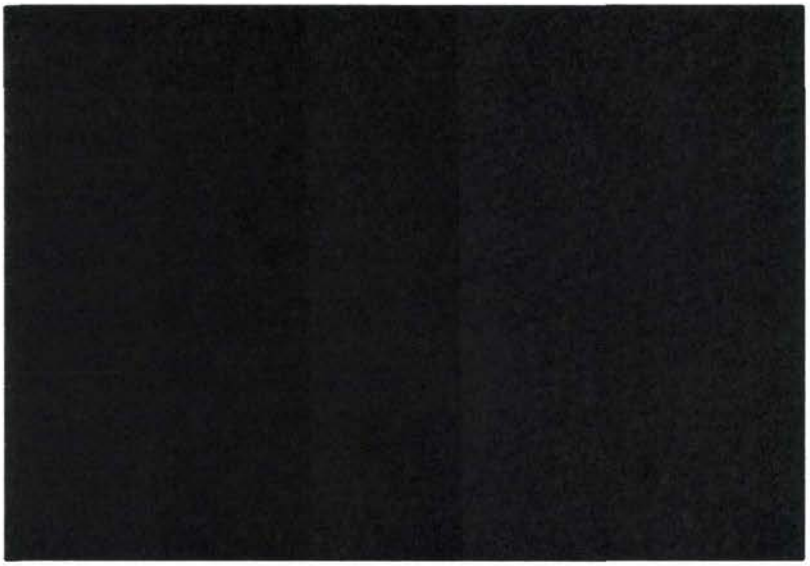
In recent years, Plant Crist has undertaken a plan to blend Illinois Basin coal with other low sulfur bituminous coals such as Colombian, Central Appalachian and Colorado coals in order to take advantage of an increased Btu content and decreased sulfur content of the blended product. This practice of blending Illinois Basin coal with lower sulfur coals is scheduled to continue. Crist and Smith's portfolio currently

includes coals from the Central Appalachian region and the Illinois Basin region. These coals are being delivered by rail to the Alabama State Docks (ASD) in Mobile, Ala.



Daniel

The chart below shows a breakdown of the current Daniel suppliers and volume commitments, including options, through 2017.



Source: July DEPS (2013-2014)
2013 Energy Budget June Update (2015-2017)

[redacted]

[redacted]The goal for future years, if

economics warrant, would be to maintain this diversity. Should supply problems occur, this diverse portfolio of suppliers would help ensure that other suppliers could continue seamless deliveries to the plant. Gulf will also continue its policy of testing various import as well as domestic coals.

[redacted]

Both Illinois Basin and Central Appalachian coals can be railed directly to Daniel. At this time, it is uncertain if the plant will need some time to acquire additional plant equipment necessary for burning Illinois Basin coals. The procurement group will need to be cognizant of the environmental controls placed on the units and ensure that the coals purchased will meet the environmental requirements.

[redacted]

[redacted]

[redacted]

GULF POWER
COAL TRANSPORTATION STRATEGY FOR 2014

Transportation Program Overview

Plants Crist and Smith

Crist and Smith have the ability to receive both import and domestic coal by barge. Western coals can be transported by the Burlington Northern Santa Fe Railway (BNSF) or Union Pacific Railroad (UP) to terminals on the Ohio and Mississippi rivers or via interchanges with the Canadian National Railway (CN), Norfolk Southern (NS) or CSX Transportation Inc. (CSXT) to the Alabama State Docks facility in Mobile, Ala., and then barged to the plants. Illinois Basin or Central Appalachian coal can be transported by barge or by a combination of rail and barge to these plants as well.

Eastern coal can be transloaded at the Alabama State Docks facility via interchanges with the Canadian National Railway (CN), CSX Transportation Inc. (CSXT), Alabama and Gulf Coast Railway (AGR), and Norfolk Southern (NS) railroads. Import coal can be delivered by ocean vessel to the Alabama State Docks for barge movement to the plants. Currently, Crist and Smith receive Central Appalachian coal and Illinois Basin coal. Smith also is receiving some import test coal.

NS agreement NS-9679 provides for rail transportation of the Alpha Coal Sales Company, LLC coal to the Alabama State Docks through

Dec. 31, 2014. The agreement has an annual minimum volume requirement [redacted].

CN Agreement CN-517554-AB provides for rail transportation of Illinois Basin coal from Foresight Energy and American Coal Company to the Alabama State Docks through Dec. 31, 2013. [redacted]

Crounse Corporation Agreement (GU12002-B) provides barge transportation for the Argus Energy coal loaded on the Big Sandy River in West Virginia and transported to Mobile, Alabama. The Crounse agreement runs through March 31, 2014.

Fuel movement to Crist and Smith from Mobile, Alabama is primarily by a single barge carrier, Marquette Transportation Company, LLC (Marquette). The Marquette agreement (SC09006-T) provides for transportation of coal to both plants from the Alabama State Docks and Mobile Bay and River area. The Marquette agreement expires Dec. 31, 2014.

Plant Scholz

Scholz is rail served by the CSXT railroad. The plant has the ability to receive both domestic and import coal. Import coal could be brought into the Alabama State Docks and then transloaded into railcars for movement to the plant.

Scholz has an agreement with the CSXT railroad (CSXT-C-83791) that expires Dec. 31, 2014. This agreement specifies that [redacted] of all deliveries must move on the CSXT railroad, with an annual maximum [redacted]

Coal deliveries to Scholz will cease at the end of 2014 and the plant will consume inventory prior to the plant's retirement in April 2015.

Plant Daniel

Daniel is served by the Mississippi Export Railroad (MSE) that interchanges with the CSXT and the CN. Daniel accesses Powder River Basin (PRB) and Colorado coal sources via multiple rail hauls to the MSE from the BNSF, UP and CN railroads.

Daniel can also take advantage of import coals, when economical, through the Alabama State Docks. Import coal is transloaded from an ocean vessel at the Alabama State Docks facility to railcars for shipment to the plant by the CN and interchanged with the MSE. Daniel can also receive Central Appalachian coal via the CSXT and interchange with the MSE. Another potential source of Central Appalachian coal is via the NS railroad through an interchange agreement with the CN railroad.

UP agreement UP-55105 provides for rail transportation of Colorado coal to Memphis in conjunction with CN-523746-AA for final delivery to Daniel through Dec. 31, 2013. The agreement has an annual minimum

volume requirement of [redacted] and a maximum [redacted] of coal that can be shipped.

BNSF agreement BNSF-12677 provides for rail transportation of PRB coal to Memphis, TN where BNSF interchanges with CN to deliver the PRB coal to Daniel. The BNSF agreement expires Dec. 31, 2014 [redacted]

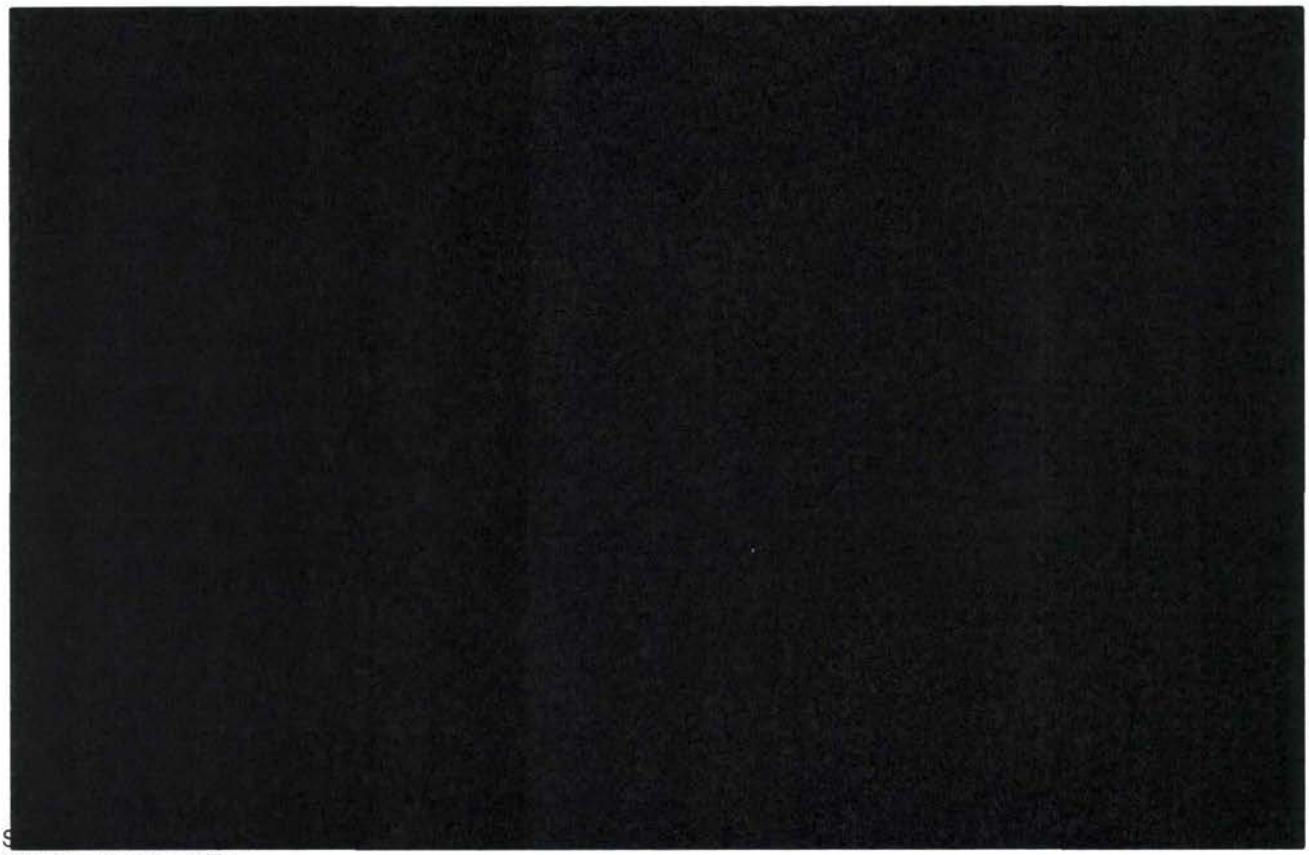
CN/MSE agreement CN-523746-AA provides for rail transportation of PRB and Colorado coal from Memphis, TN to Daniel. The CN/MSE agreement expires Dec. 31, 2013. [redacted]

Budget

During the next 10 years, Gulf is budgeted to transport approximately 2-3 million tons of coal per year. There is a decrease in transportation costs from 2013 to 2015 that is directly tied to the loss of burn during this period.

From 2014 to 2021, the majority of the uncommitted coal requirements are projected to be met by purchasing a [redacted] blend of Illinois Basin coal and Central Appalachian coal. The increase in transportation costs are directly related to the increase of the volume of coal to be transported and changes related to the forecast for rail rates. Actual coal purchases may be different than current projections based on economic evaluations.

The chart below shows the forecasted coal volume and transportation costs for Gulf's coal-fueled plants.



2013 (Jan - May) Actual Tons
2013 Energy Budget - June Update

Coal Transportation Procurement Strategy

A transportation strategy must address reliability, competitive prices, flexibility in volume commitments and the ability to adjust coal movements to changing coal supply sources. The following information addresses these areas and identifies tactical plans to manage them.

Tactical Plan

Plants Crist and Smith

NS agreement NS-9679 provides for rail transportation of Central Appalachian coal to the Alabama State Docks through Dec. 31, 2014. [redacted]

CN Agreement CN-517554-AB provides for rail transportation of Illinois Basin coal to the Alabama State Docks through Dec. 31, 2013 [redacted]

Crounse Corporation Agreement (GU12002-B) provides barge transportation for Central Appalachian coal loaded on the Big Sandy River in West Virginia and transported to Mobile, Alabama for final movement to Plant Smith by Marquette Transportation Company, LLC (Marquette). The Crounse agreement runs through December 31, 2013. [redacted]

Marquette agreement (SC09006-T) provides primary barge transportation of coal from the Alabama State Docks to Crist and Smith. Marquette agreement (SC09004-T) and Heartland Barge Management agreement (SC09005-T) provide a supply of barges to move coal to Crist and Smith. These agreements expire Dec. 31, 2014.

[redacted]

Plant Scholz

Scholz has an agreement with the CSXT railroad (CSXT-C-83791) that expires Dec. 31, 2014.

Plant Daniel

UP agreement UP-55105 provides for rail transportation of Colorado coal to Memphis in conjunction with CN-523746-AA for final delivery to Daniel through Dec. 31, 2013. [redacted].

BNSF agreement BNSF-12677 provides for rail transportation of PRB coal to Memphis, TN where BNSF interchanges with CN to deliver the PRB coal to Daniel. The BNSF agreement expires Dec. 31, 2014.

CN/MSE agreement CN-523746-AA provides for rail transportation of PRB and Colorado coal from Memphis, TN to Daniel. The CN/MSE agreement expires Dec. 31, 2013. [redacted]

Gulf Power 2014 Natural Gas Procurement Strategy

Gas Program Overview

Natural Gas is used for primary fuel at the Smith 3 combined cycle unit, boiler lighter fuel at Crist Units 4-7, and for generation secured under purchased power agreements beginning in 2009. Prior to 2002, natural gas represented a relatively small portion of Gulf's overall fuel budget. With the addition of the Smith 3 combined-cycle unit in 2002, natural gas became a more significant portion of Gulf's overall fuel budget.

Gulf Power's natural gas procurement strategy is to purchase a cost effective yet highly reliable fuel supply to support the operation of its generating facilities. Securing competitive fuel prices for its customers and minimizing both price and supply risk are the governing considerations in developing Gulf's fuel procurement strategy.

Projected Natural Gas Purchases

Southern Company Services (SCS) as agent for Gulf purchases natural gas to be delivered to Plant Crist for lighter purposes on the coal fired units and to Plant Smith as primary fuel for Unit 3 which is a combined cycle generating unit. SCS will also purchase natural gas to serve as primary fuel for the Coral (Baconton), Southern Power (Dahlberg) and Shell (Central Alabama) purchased power agreements. Gulf has contracted for storage capacity at Bay Gas Storage near Mobile, AL and at Southern Pines Energy Center near Hattiesburg, MS and will purchase natural gas to maintain targeted quantities of gas in storage during the year.

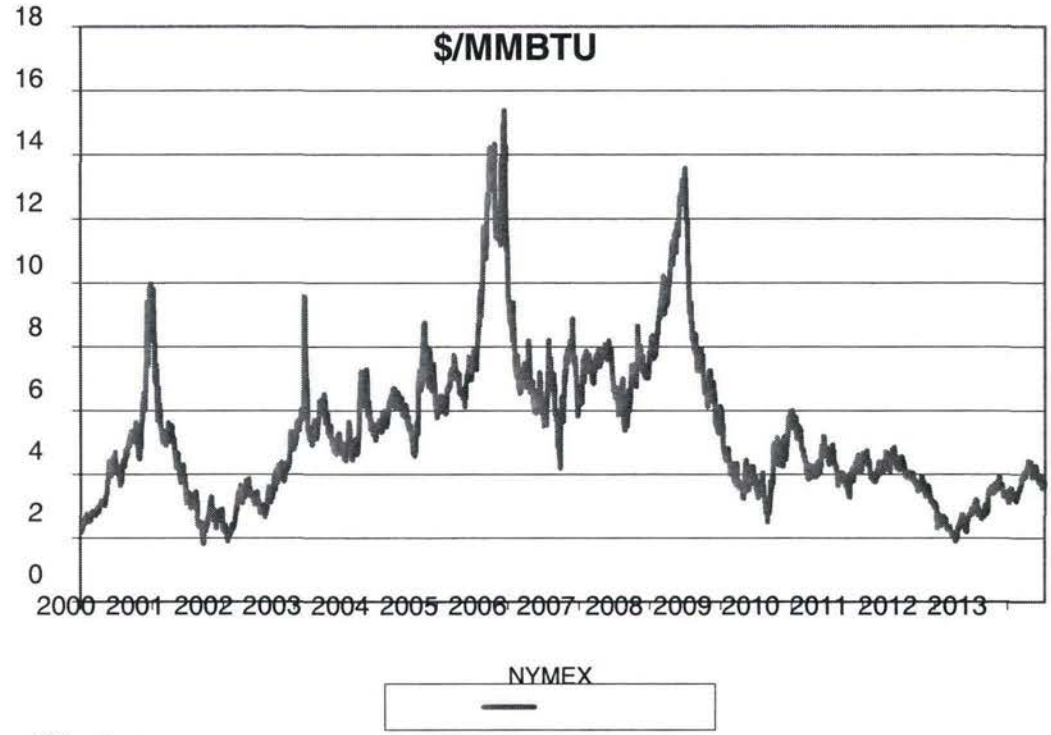
Procurement Strategy

Gulf's strategy for gas procurement is to purchase the commodity using long term and spot agreements at market prices. Fuel purchased at market over a

long period is a low cost option for customers. [redacted] For Gulf, spot-market contracts have a term of less than one year and long-term contracts have a term of 1 year or longer. All natural gas, regardless of whether it is bought under long-term contracts or spot-market contracts, is purchased at market based prices. While fuel purchased at market over long periods is a low cost option for customers, it does expose the customers to short-term price volatility. Since these price fluctuations can be severe, Gulf Power, at the direction of the Florida Public Service Commission, will attempt to protect its customers against short-term price volatility by utilizing hedging tools. It is understood that the cost of hedging will sometimes lead to fuel costs that are higher than market prices but that this is a reasonable trade-off for reducing the customers' exposure to fuel cost increases that would result if fuel prices actually settle at higher prices than when the hedges were placed.

The following graph of actual natural gas prices is an indication of price volatility in the gas commodity market:

Historical Natural Gas Prices - NYMEX



Pricing Strategy

Gulf Power will continue to purchase gas, both under long-term and spot contracts at market based prices. However, pursuant to Commission order, Gulf Power will financially hedge gas prices for some portion, generally between [redacted] percent of Gulf Power's projected annual gas burn for the current year, in order to protect against short-term price swings and to provide some level of price certainty. This [redacted] percent hedge range allows Gulf Power to provide a degree of price certainty and protection against short-term price swings while still allowing the customers to participate in markets where natural gas prices are low. Gulf Power will secure natural gas hedges over a time period not to exceed [redacted] months, per the following schedule:

Period	Lower Target Hedge %	Upper Target Hedge %
Prompt Year (2014)	[redacted]	[redacted]
Year 2 (2015)	[redacted]	[redacted]
Year 3 (2016)	[redacted]	[redacted]
Year 4 (2017)	[redacted]	[redacted]
Year 5 (2018)	[redacted]	[redacted]

Note: The annual hedge percentage is based on the budgeted annual gas burn

Although SCS will target the levels shown in the table above, SCS may accelerate or decelerate the plan accordingly based on market conditions. Gulf's hedging targets are expressed on an annual basis due to the potential for large variances in month to month gas consumption. The monthly variance in gas burn is due to Gulf's units being dispatched on an economic basis with the other generating units in the Southern electric system and the impact of unit outages on Gulf's total gas burn.

SCS, working in partnership with Gulf Power, develops short-term hedge strategies based on current and projected market conditions [redacted] SCS will employ both technical and fundamental analysis to determine appropriate times to hedge. However, the objective is not to speculate on market price or attempt to outguess or "beat the market". [redacted]

While the hedging program will protect the customer from short-term price spikes, hedges can also lead to higher costs when natural gas prices fall subsequent to entering hedges. Gulf Power will limit the amount of fixed-price hedges to a maximum of [redacted] percent of the projected fuel burn for the upcoming year. In addition, Gulf Power will limit option priced hedges to [redacted] percent of its projected burn. Finally, in order to protect its customers from market exposure in subsequent years, Gulf Power will take forward hedge positions for up to [redacted] months into the future.

Gulf Power's 2014 Oil Procurement Strategy

Oil Program Overview

Oil is used at Gulf predominantly for boiler lighting. Oil is used as a boiler lighter fuel at Crist units 4-7, Daniel 1&2, Scherer 3, Scholz 1&2 and Smith 1&2. Oil is also the primary fuel at the Smith A CT unit and as back-up fuel at the Coral (Baconton) and Southern Power (Dahlberg) CT units and the Shell (Central Alabama) CC Plant currently under purchase power agreements with Gulf. Overall, oil use is projected to be a small portion of Gulf's overall fuel budget.

Procurement Strategy

Gulf's strategy for oil procurement is to purchase the commodity at market prices. Fuel purchased at-market over a long period is a low cost option for customers.

Gulf purchases fuel oil on an annual basis through a formal bidding process. As part of this bidding process, Gulf negotiates predetermined contracts to set the

index based market price for the commodity and delivery adders for fuel oil delivery to each plant. As inventories are depleted during the year, Gulf will purchase additional fuel oil quantities based on the negotiated contract for the plant.

Pricing Strategy

Oil pricing will be indexed to current market prices at the time purchases are made. Since fuel oil is such a small portion of the overall fuel budget, Gulf does not currently plan to financially hedge oil prices.

Gulf Power Company Risk Management Policy

I. Introduction

Natural gas has become a large part of the Gulf Power Company (Company) fuel program. This increased need, combined with the market price volatility associated with natural gas and purchased energy, has created a need to begin hedging the risks related to the Company's overall fuel program.

II. Objectives

The primary objective of this Risk Management Policy (RMP) is to establish guidelines for use of hedging transactions associated with the Company's fuel program. Hedging transactions will allow the Company to:

- Reduce price volatility

- Provide more predictable stability to customers, and
- Provide additional flexibility and options in the procurement of fuel.

III. Guidelines

The risk management guidelines of The Southern Company require any business unit engaging in risk management activities to establish a Risk Oversight Committee (ROC). The officer listed below in Section IV will serve as the Company's ROC for this program.

The Southern Company Derivatives Policy states:

> "It is the policy of The Southern Company that derivatives are to be used only in a controlled manner, which includes identification, measurement, management, control and monitoring of risks. This includes, but is not limited to, well-defined segregation of duties, limits on capital at risk, and established credit policies. When the use of derivatives is contemplated, this policy requires that a formal risk management plan be developed that adheres to The Southern Company Risk Oversight Committee Business Unit Guidelines. This policy also requires that, prior to initiation of a risk management program that makes use of derivatives, the risk management program must be approved by both the Chief Financial Officer of the respective Southern Company subsidiary and the Chief Financial Officer of The Southern Company."

The Southern Company Generation Risk Management Policy (SCGen RMP), attached in Section 6 of this document, will be the governing policy in the administration of the Company's fuel procurement program. The SCGen RMP provides all criteria specified in the above extract from the Southern Company Derivatives Policy.

The Gulf Power Company Board of Directors has authorized the use of hedging transactions relating to contracts and other agreements for fuel supplies. The board resolution is shown below:

> "**RESOLVED,** That The Southern Company System Policy on Use of Derivatives (the "Policy") as presented to the meeting is hereby approved; and
>
> **RESOLVED FURTHER,** That the Officers are hereby authorized to effect derivative transactions that comply with the policy, including swaps, caps, collars, floors, swap options, futures, forward and options, relating to energy and associated commodities, weather, interest rates, currencies, and contracts and other arrangements for fuel supplies; and
>
> **RESOLVED FURTHER,** That in connection with the foregoing, the officers are hereby authorized to take any and all actions and to execute, deliver and perform on behalf of the Company any and all agreements and other instruments as they consider necessary, appropriate or advisable, each such agreement or other

instrument to be in such form as the officers executing the same shall approve, the execution thereof to constitute conclusive evidence of such approval."

IV. Process

Certain officers of the Company were given authority to enter into hedging transactions that they consider necessary in order to reduce risk associated with procuring fuel and energy. The authorized officers are Vice President, Chief Financial Officer and Comptroller for Gulf Power Company or his designee.

Once authorization has been received, Southern Company Services Fuel Services, agent for Gulf Power Company, will conduct all hedging transactions in accordance with the Southern Company Generation Risk Management Policy.

It is the responsibility of SCGen Risk Control (the mid-office) to inform the Fuel Manager for Gulf Power Company or the Regulatory Accounting Manager for Gulf Power Company about the use of hedging transactions associated with Gulf generation resources and to provide open position values (mark to market) to the above noted individuals and the Gulf Chief Financial Officer and Comptroller.

Southern Company
Energy Trading Risk Management Policy

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CONTENTS

Policy Section		Page
I.	Introduction	1
II.	Purpose	1
III.	Business Objectives	1
IV.	Business Strategies	1
V.	Authorizations	2
VI.	Segregation of Duties	2
VII.	Market Risk Identification	3
VIII.	Market Risk Measurement and Valuation	3
IX.	Market Risk Limits	4
X.	Credit Risk	4
XI.	New Products	4
XII.	Funding Liquidity	5
XIII.	Operating Procedures and Systems	5
XIV.	Accounting and Tax	5
XV.	Legal	6
XVI.	Monitoring and Reporting	6
XVII.	Personnel Trading	6
XVIII.	Business Recovery	6
XIX.	Compliance	6
XX.	Independent Review	7
XXI.	Policy Amendments	7
XXII.	Terminology	7

APPENDIXES

A.	Approved Business Objectives	A–1
B.	Approved Commodities	B–1
C.	Approved Instruments	C–1
D.	Authorizations	D–1
E.	Segregation of Duties	E–1
F.	Market Risk Measurement	F–1
G.	Daily Income Notification Levels	G–1
H.	Market Risk Limits	H–1
I.	Incumbent Listing; Authorized Individuals	I–1
J.	Accounting and Tax	J–1
K.	Employee Acknowledgement	K–1
L.	Definitions	L–1

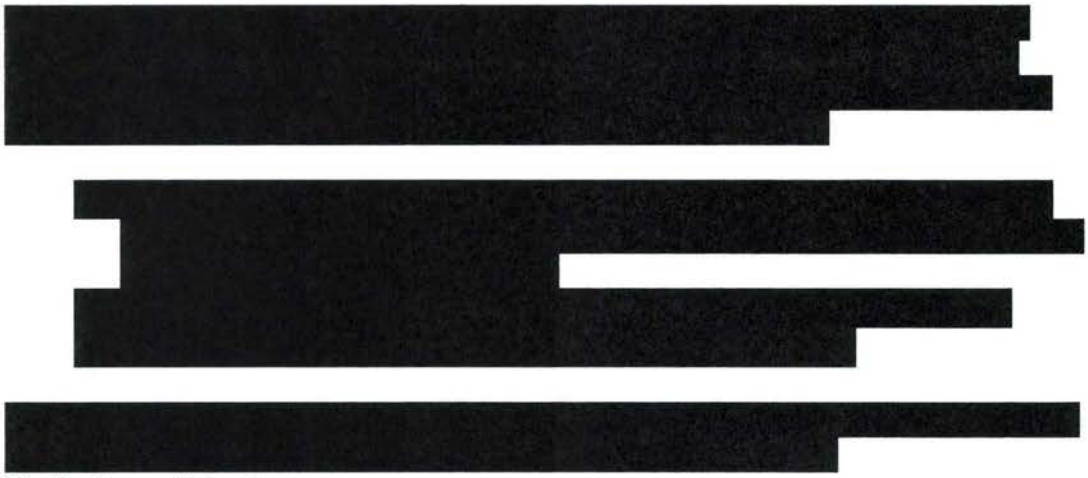
I. Introduction

In August 1997, the Southern Company Risk Oversight Committee ("SROC") approved a set of risk management guidelines. Also, at various times during 2000 through 2002, the boards of directors for Southern Company, the Operating Companies (Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company), and Southern Power Company ("SPC") adopted the Southern Company Policy on the Use of Derivatives ("Derivatives Policy"). During 2006, the risk oversight and governance framework for Southern Company continued to evolve to further refine the oversight structure and to reflect organizational changes since the original SROC approved risk management guidelines in August 1997. As part of this evolution, the SROC was reconstituted, and a Generation Risk Oversight Committee was formed. These groups, along with the Risk Advisory and Controls Committee, replaced the Energy Risk Management Board and assumed its responsibilities.

Effective November 19, 2007, as a result of the Separation Protocol, certain functions for SPC were separated from the Operating Companies and certain communications between them was restricted. It was decided that SPC would no longer attend or have representation on the Generation Risk Oversight Committee. This decision prompted the need for a Southern Power Risk Oversight Committee and separate SPC risk monitoring. The Generation Risk Oversight Committee will continue to monitor the consolidated energy trading risks, including SPC positions.

The Southern Company Derivatives Policy requires any business unit engaging in energy trading and marketing activities to develop a risk management policy. This policy must be consistent with the Southern Company Enterprise Risk Management Framework document and must include, but not be limited to, well-defined segregation of duties, limits on capital at risk and established credit policies.

II. Purpose

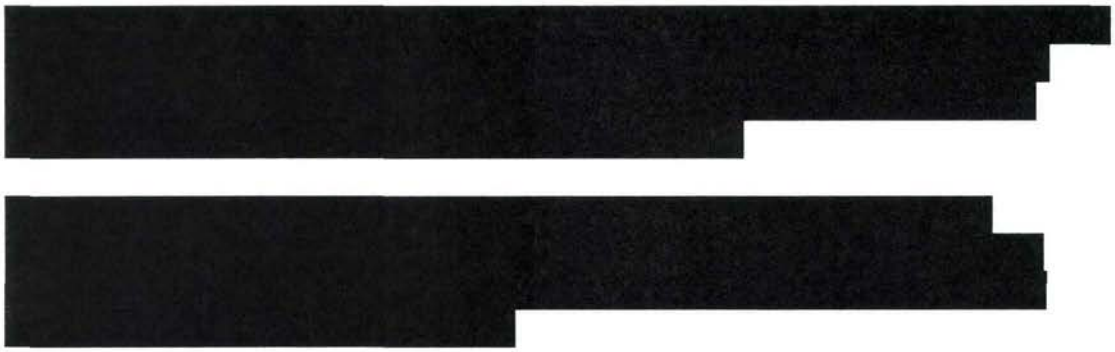


III. Business Objectives

The Approved Business Objectives for the trading activities performed by Authorized Individuals are defined in Appendix A.

IV. Business Strategies

The business objectives are achieved by entering into transactions involving the approved commodities shown in Appendix B.



Various contract types or financial instruments will be used to achieve the Approved Business Objectives. The Approved Risk Management Instruments are listed in Appendix C. SCS Risk Control must be consulted before the execution of any Approved Risk Management Instruments that have not been previously used. SCS Risk Control must ensure that the requirements set forth in this RMP can be followed with respect to those instruments.

V. Authorizations

Appendix D contains the individuals, boards, and committees authorized to carry out various activities, reviews, and approvals.

VI. Segregation of Duties

[redacted]

Appendix E shows the organizational separation of function required by this RMP. The following is a summary of the responsibilities of the different functions:

Origination and Structuring: The functions of origination and structuring include the following responsibilities:

[redacted]

Confirmation, Monitoring, and Reporting: The functions of trade confirmation, risk monitoring, and risk reporting include the following responsibilities:

[redacted]

Settlement: The function of settlement includes the following responsibilities:

[redacted]

[redacted]

Cash Management: SCS Treasury is responsible for receiving and disbursing all funds from or to counterparties and for the delivery of margin / collateral requirements. SCS Treasury will also be responsible for investment of collateral provided by counterparties.

Accounting: SCS Accounting is responsible for posting transactions to the general ledger and reconciling the subledgers to the general ledger.

VII. Market Risk Identification

[redacted]

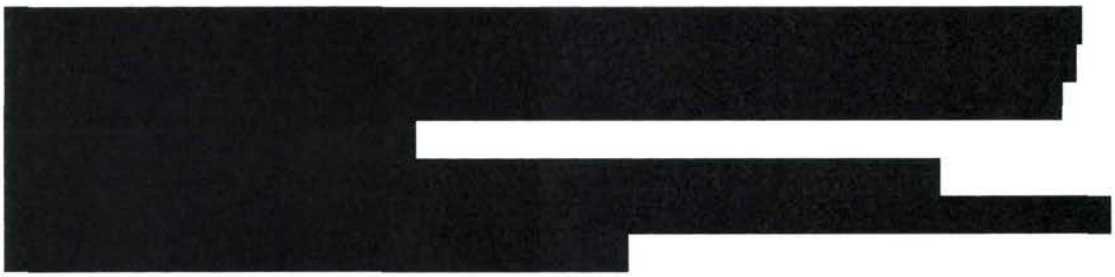
VIII. Market Risk Measurement and Valuation

[redacted]

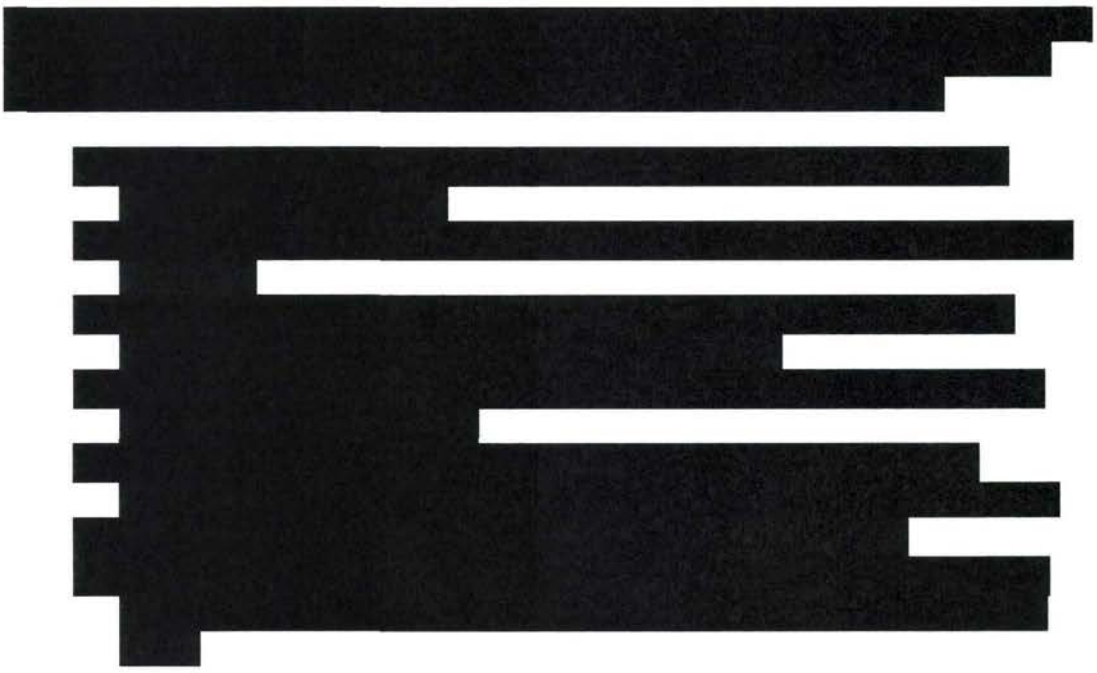
IX. Market Risk Limits

Exposure Limits	The maximum exposure limits are shown in Appendix H. The maximum exposure limit for each business objective should not exceed the limits specified in Appendix H.
Notifications	Certain notifications to management are required as defined in Appendix G.
Limit Excess Reporting	Irrespective of other provisions contained in this RMP, limit overages may occur. Each occurrence shall be promptly reported by SCS Risk Control to individuals identified in Appendix G.

X. Credit Risk



XI. New Products



XII. Funding Liquidity

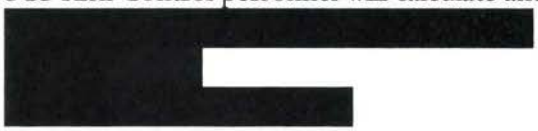
XIII. Operating Procedures and Systems

XIV. Accounting and Tax

XV. Legal

XVI. Monitoring and Reporting

SCS Risk Control personnel will calculate and report the following items on a daily basis:



The Portfolio Management group will prepare regular position reports. The back office will report preliminary gross margins or P&L on a daily basis.

XVII. Personal Trading

XVIII. Business Recovery

XIX. Compliance

[redacted]

[redacted]

XX. Independent Review

[redacted]

XXI. Policy Amendments

[redacted]

XXII. Terminology

Definitions of terminology used in this RMP are contained in Appendix L.

APPENDIX A
APPROVED BUSINESS OBJECTIVES

Fleet Operations and Trading

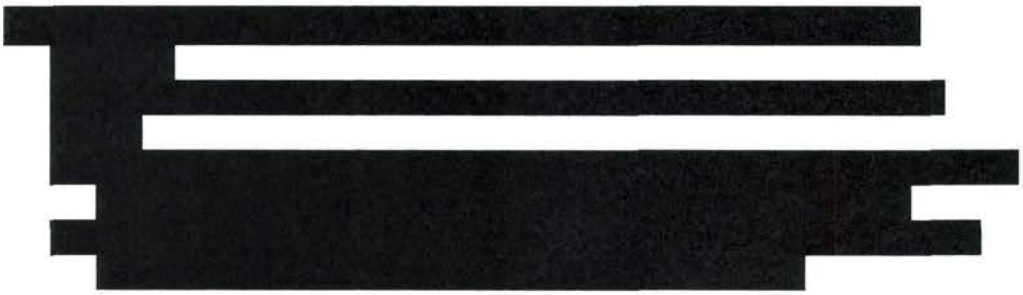
The primary objectives of Fleet Operations and Trading are to:

In addition to the primary objectives, Fleet Operations and Trading may execute secondary activities as limited by Appendix H to achieve the following secondary objectives to the extent permitted by all applicable policies and regulations:

Southern Power Company Trading & Asset Management

The primary objectives of the SPC Trading and Asset Management activities are the following:

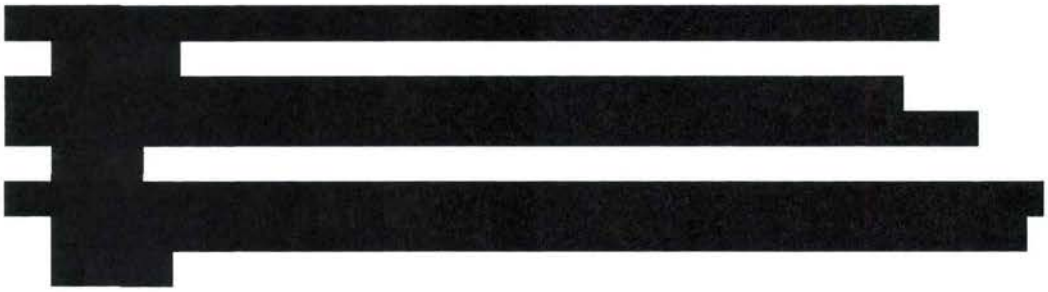
In addition to the primary objectives, SPC Trading & Asset Management may execute secondary activities as limited by Appendix H to achieve the following secondary objectives to the extent permitted by all applicable policies and regulations (including, but not limited to the IIC and Separation Protocol):



All SPC Secondary Strategies must be approved by the SPC Chief Financial Officer and the SPC Chief Commercial Officer.

Natural Gas Fulfillment Function

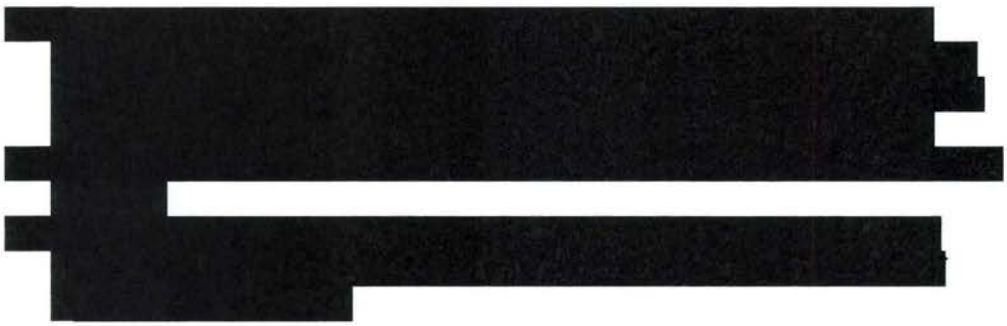
The primary objectives of the Natural Gas Fulfillment Function are to:



Secondary activities of the natural gas fulfillment function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading or SPC Trading & Asset Management.

Environmental Products Management Function

The primary objectives of the Environmental Products Management Function are to:



Secondary activities of the Environmental Products Management Function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading or SPC Trading & Asset Management.

Coal Fulfillment Function

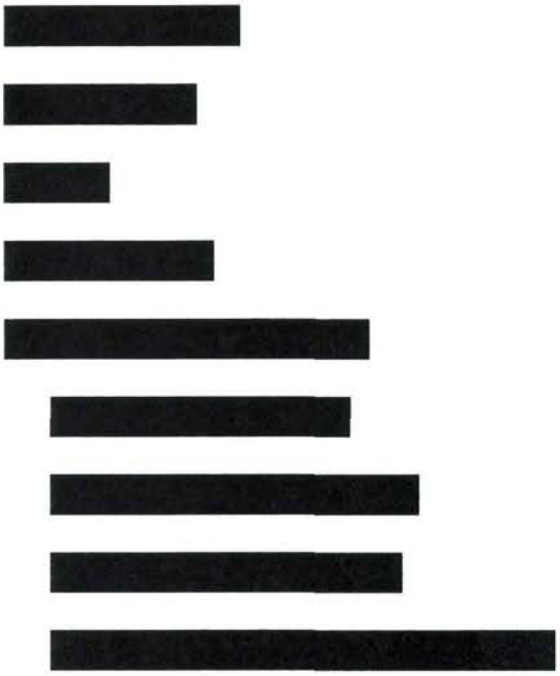
The primary objectives of the Coal Fulfillment Function are to:

[redacted]

Secondary activities of the Coal Fulfillment Function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading or SPC Trading & Asset Management.

APPENDIX B
APPROVED COMMODITIES

The approved commodities for this RMP are:



APPENDIX C
APPROVED INSTRUMENTS

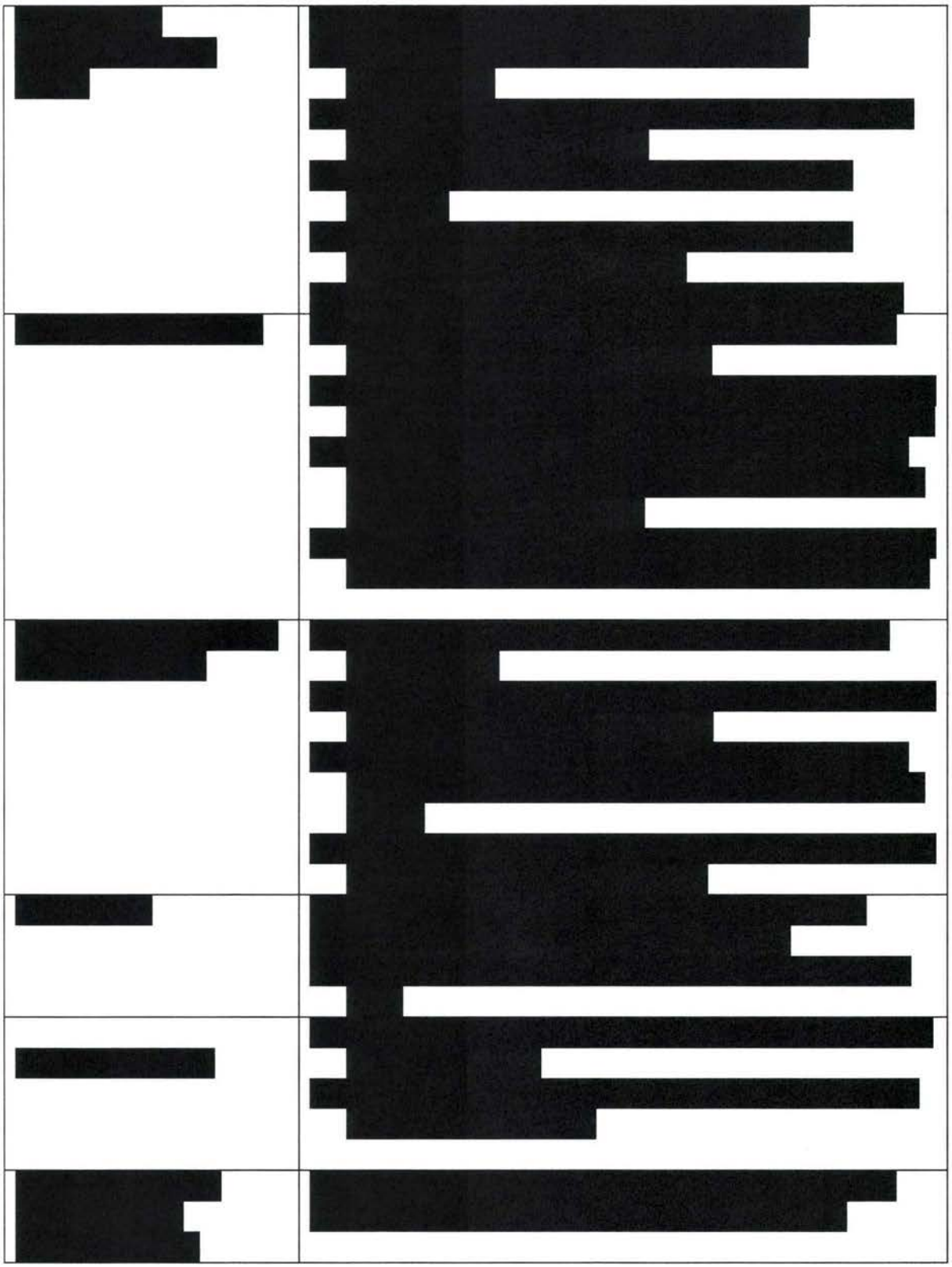
The approved instruments are:

APPENDIX D
AUTHORIZATIONS

Name	Authority
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

APPENDIX D
AUTHORIZATIONS (continued)
Energy Marketing

Name	Authority
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]



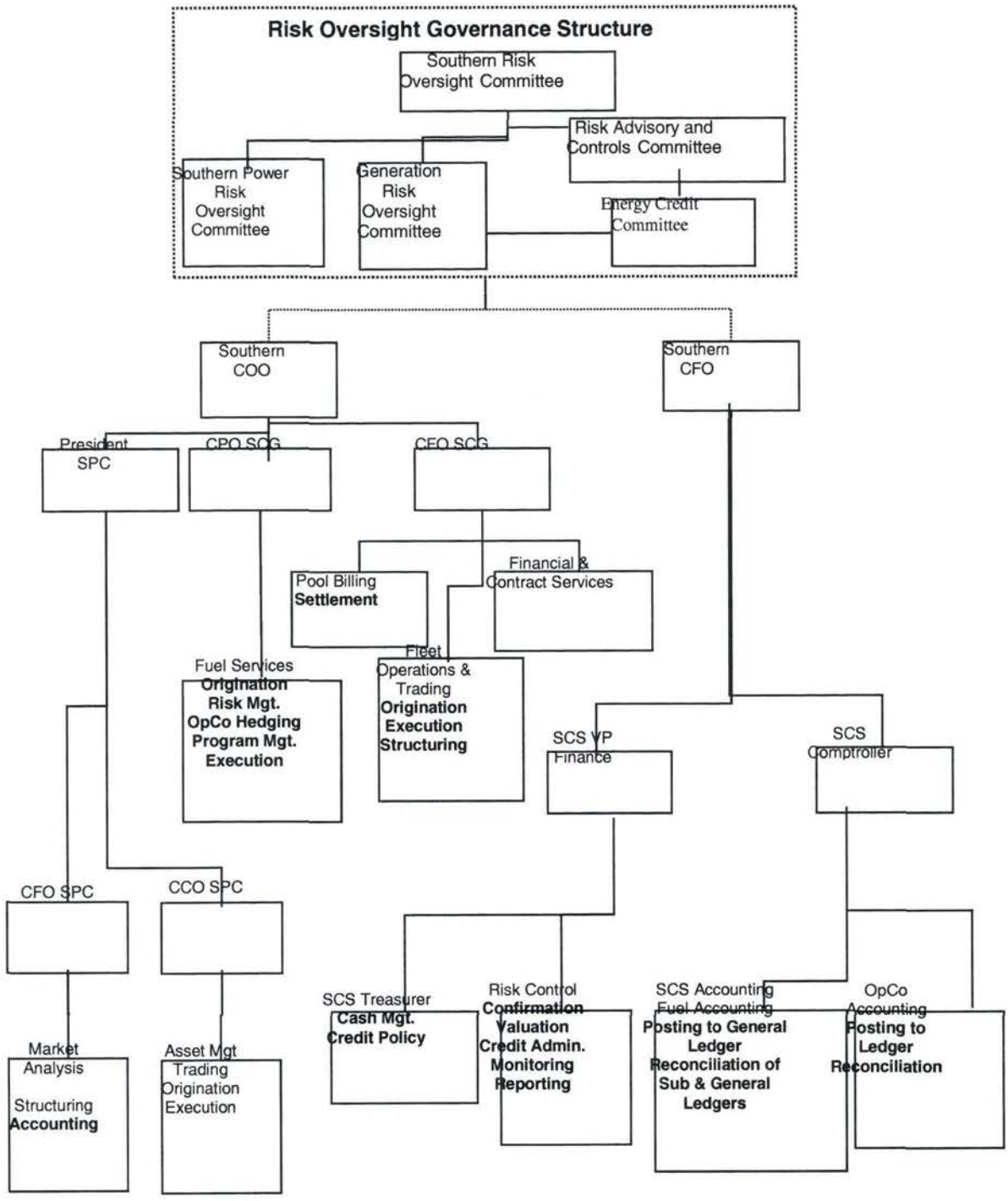
APPENDIX D
AUTHORIZATIONS (continued)
SCS Fuel Services

Name	Authority
[redacted]	[redacted]

APPENDIX E

SEGREGATION OF DUTIES

To ensure that risk management activities are properly carried out, certain functions will be separated. The following chart identifies these functions (depicted as **BOLD** bullet items) and their reporting process.



APPENDIX F
MARKET RISK MEASUREMENT

Approved Commodities	Value at Risk *Method*
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Parametric VaR Methodology

Formula Components

Component	Symbol	Comments
Value at Risk	VaR	See Equation Below
Position	PSN	Given in Applicable Measurement Units
Daily Standard Deviation of Price Change	ΔP	Given in $/Applicable Measurement Units
Holding Period – Business Days	HP	Taken From Parameters Table Shown Below
Confidence Interval Multiplier	CI	For Example: CI = 1.65 for 95-% Confidence Interval

Equation

$$VaR = PSN * \Delta P * \text{Square Root of } HP * CI$$

ParametersCommodity	Holding Period (HP)	Multiplier (CI)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

APPENDIX F
STRESS TESTING METHODOLOGY

The purpose of stress testing is to generate percentage price changes for the forward curve that answer this question:

> If an extreme event occurs, what can we expect to happen to prices and the portfolio value?

The stress test is designed to capture the expected value of an extreme event as defined by an extreme value distribution. To differentiate, there is a downward and an upward stress test.

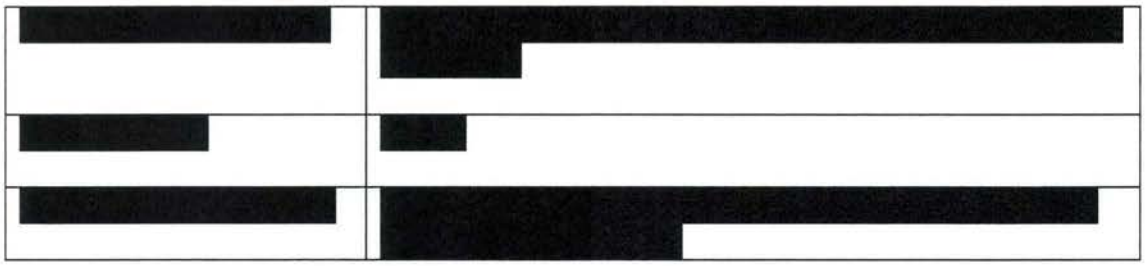
Specifically, the expected downward stress is calculated as

$$E[\Delta p/p \mid \Delta p/p < \Theta] = \text{the Integral of } f(x)xdx \text{ from negative infinity to } \Theta$$

and the expected upward stress is calculated as

$$E[\Delta p/p \mid \Delta p/p > \Theta] = \text{the Integral of } f(x)xdx \text{ from } \Theta \text{ to infinity}$$

where Θ is the threshold that defines classification as an extreme event, f(x) is an extreme value distribution fitted to a specific contract, and x is a percentage price change.



Ad Hoc Stress Testing

Ad hoc stress testing will be performed as appropriate based on price scenarios determined using alternative methods including, but not limited to, the following:

- specific historical scenarios;
- rating agency defined price changes;
- analysis of out-of-the money option trading; and
- subjectively determined price changes.

APPENDIX G
NOTIFICATION LEVELS

Position Classification	Income Change	Notify
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

APPENDIX G
NOTIFICATION LEVELS

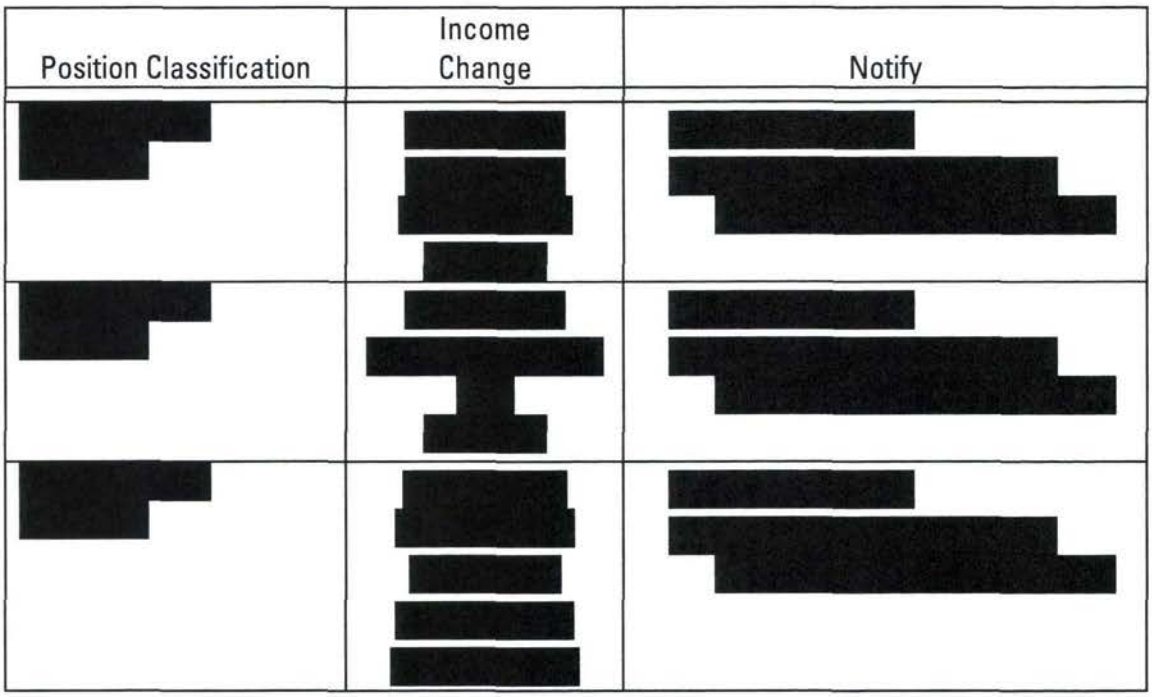
Position Classification	Income Change	Notify
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

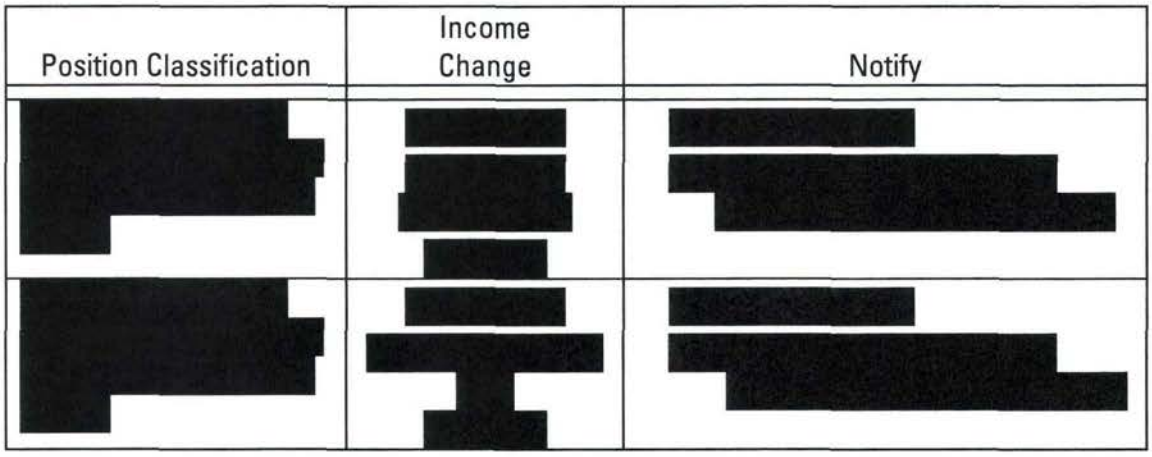
APPENDIX G
NOTIFICATION LEVELS

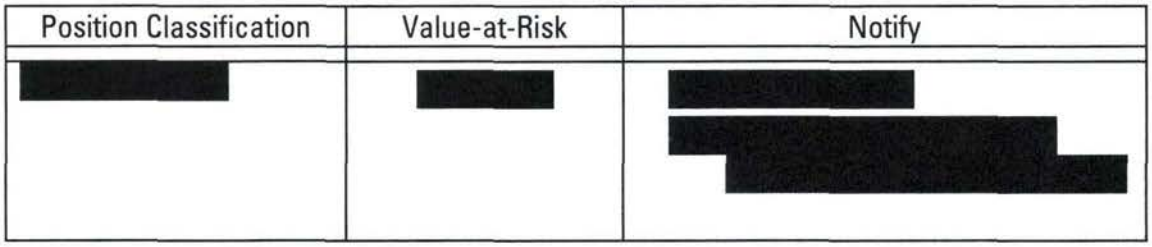
Position Classification	Value-at-Risk	Notify
[redacted]	[redacted]	[redacted]

NOTE: Recipients of notification events will only receive detailed information pertinent to their business needs, and any correspondence will be in compliance with the Separation Protocol.

APPENDIX G
NOTIFICATION LEVELS

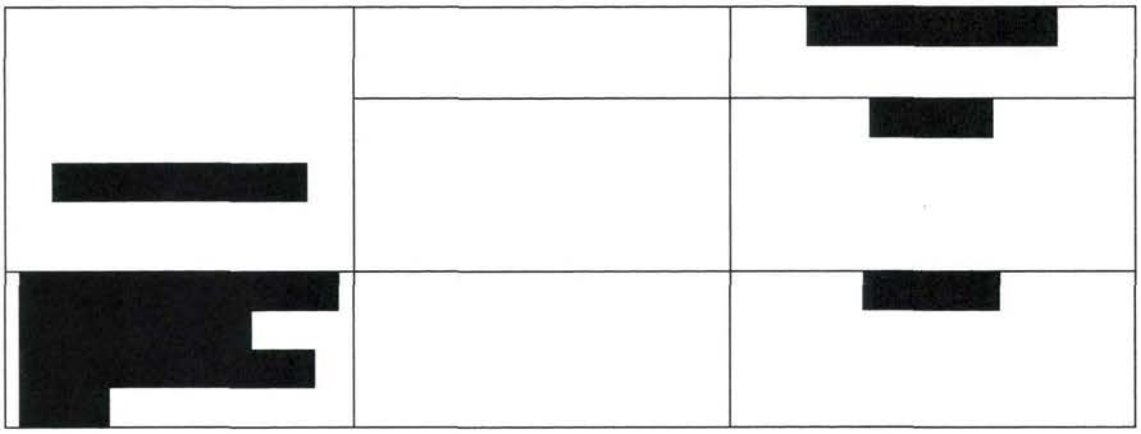






APPENDIX H
MARKET RISK LIMITS

Net Open Position Limits



NOTE: Although the value-at-risk limit applies to positions marked to market through income, VaR is calculated and monitored for all positions, and there are notification requirements as defined in Appendix G.

If such open position limits are exceeded, SCS Risk Control will calculate and equitably allocate the responsibilities to bring the positions back into compliance.

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Incumbent Listing

Title
Chief Financial Officer, Southern Company Chairman, Southern Risk Oversight Committee Chairman, Risk Advisory and Controls Committee
Chief Operating Officer, Southern Company
Chief Financial Officer, Operations
President, Southern Power Company
Chief Commercial Officer, Southern Power Company
Chief Financial Officer, Southern Power Company Chairman, Southern Power Risk Oversight Committee
Vice President, Fuel Services
Vice President, Fleet Operations and Trading
Manager, Risk Control
Manager, Energy Trading
Manager, Southern Power Trading & Asset Management
Coal Services Director
Gas Services Director
Gas Trading Manager
Gas Operations Manager

Southern Company Risk Oversight Committee

Title
CFO & CRO, Southern Company
Chairman, President, and CEO, Southern Company
EVP, President & CEO, SCS
EVP & COO, SCS
EVP, Southern Company & President & CEO, APC
EVP, Southern Company & President & CEO, GPC
EVP, Southern Company & President & CEO, MPC
EVP, Southern Company & President & CEO, Gulf
EVP, Southern Company & President External Affairs
EVP, General Counsel, and Corporate Secretary, Southern Company
EVP, Finance & Treasurer – invited guest

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Risk Advisory & Controls Committee

Title
CFO & CRO, Southern Company
CFO, APC
CFO, GPC
CFO, Gulf Power Company
CFO, MPC
CFO, Operations
CFO, SPC
CFO, VP & Treasurer Southern Communications
VP Comptroller & Treasurer, SNC
Comptroller, CAO, & SVP, SCS
EVP Finance & Treasurer, SCS
VP & Associate General Counsel, SCS
Internal Auditing Director – invited guest

Southern Company Generation Risk Oversight Committee

Title
Regulatory Affairs & Energy Policy Director, SCS
EVP of E&CS, SCG
Chief Production Officer, SCG
Legal Counsel, Balch & Bingham – invited guest
CFO, Operations
Enterprise Risk Management Director
Internal Auditing Director – invited guest

Southern Power Risk Oversight Committee

Title
CFO, SPC
President, SPC
Chief Commercial Officer, SPC
Senior Production Officer, SPC
Compliance & Corporate Affairs Director, SPC

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Generation Energy Credit Committee

Title
Assistant Treasurer, SCS
VP, Fuel Services
VP, Fleet Operations & Trading, SCG
Enterprise Risk Management Director

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS (continued)

Authorized Individuals

Title	Name	Approved Commodities								
		Electricity		Natural Gas						
		Energy	Trans.	Gas	Trans-port	Storage	Coal	Oil	Allow-ances	RECs
Southern Company Generation										
Energy Term Trading Mgr.	David Hansen	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	Tim Taylor	X	X	(2)						
Term Trader	Kyo Kelly	X	X	(2)						
Term Trader	Frank Harris	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	Rodrick Ingram	X	X	(2)			(2)	(2)	(2)	(2)
Trading Operations Mgr.	Daryl McGee	(1)	(1)							
Hourly Trading Mgr.	Steve Lowe	X	X							
Energy Coordinator	Bill Brown	X	X							
Energy Coordinator	Blair Ellington	X	X							
Energy Coordinator	Shannon Gunnells	X	X							
Energy Coordinator	Brian Calhoun	X	X							
Energy Coordinator	Jacob Key	X	X							
Energy Coordinator	Larry Savage	X	X							
Energy Coordinator	Michael Turberville	X	X							
Scheduler	Matt Bauman	(1)	X							
Scheduler	Bobby Brown	(1)	X							
Scheduler	Dana Booze	(1)	X							
Scheduler	Brian Elliott	(1)	X							
Scheduler	Brian Calhoun	(1)	X							
Scheduler	Stacey Pruitt	(1)	X							
Scheduler	Michael Roper	(1)	X							
Scheduler	Stacey Smith	(1)	X							
Scheduler	Robby Wentz	(1)	X							
Trading Analyst	Susan Olive	(1)	(1)							
Trading Analyst	Martha Russell	(1)	(1)							
Team Leader	Stephen Stepkoski	(1)	(1)							
Team Leader	Christopher Strong	(1)	(1)							

Notes:
(1) Authority to make changes to transactions including entering transactions related to loss adjustments and full/partial requirements customers.
(2) Authority to direct a transaction.

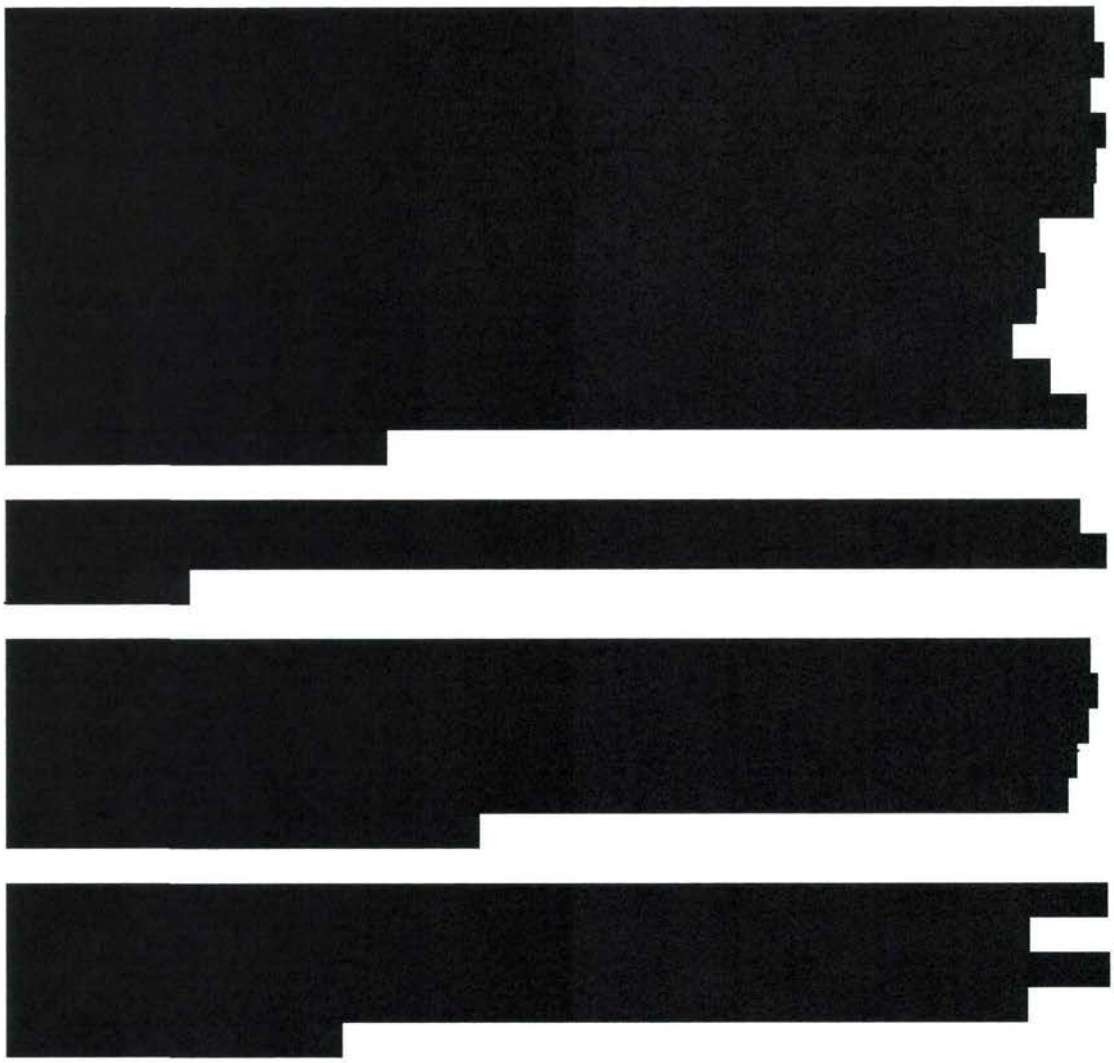
APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS (continued)
Authorized Individuals

Title	Name	Approved Commodities								
		Electricity		Natural Gas						
		Energy	Trans.	Gas	Trans-port	Storage	Coal	Oil	Allow-ances	RECs
SCS Fuel Services										
Gas Services, Director	Carl Haga			X	X	X		X		
Gas Operations Mgr.	Roy Hiller			X	X	X				
NG Buyer - Physical	John Benefield			X	X	X				
NG Buyer - Physical	Karen Gandy			X	X	X		X		
NG Buyer - Physical	Carol Thomasson			X	X	X				
NG Buyer - Physical NG Buyer - Financial	Vicki Gaston			X	X	X				
Gas Trading Mgr.	Bronson Kilgore			X				X		
NG Buyer - Financial	Tonya Gary			X	X	X		X		
NG Buyer - Physical NG Buyer - Financial	Joshua Hutto			X				X		
NG Scheduler	Tisha Dale				X	X				
NG Scheduler	Russ Hall				X	X				
NG Scheduler	Shelanda Augustus			X	X	X				
NG Scheduler	David Sokira				X	X				
NG Scheduler	Billie Williams				X	X				
Coal & Transport Procure Manager	Tony Reed						X			
Emissions Trader	Vacant								X	X
Emissions Trading Mgr	Vallery Brown								X	X
Emissions Trader	Richard Taylor								X	X

Title	Name	Approved Commodities								
		Electricity		Natural Gas						
		Energy	Trans.	Gas	Trans-port	Storage	Coal	Oil	Allow-ance	RECs
Southern Power Company										
Manager - Trading & Asset Management	Joe Styslinger	X		(2)			(2)	(2)	(2)	(2)
Asset Management	Tracy Ellis			(2)						
Asset Management	Vacant			(2)						
Asset Management	Ty Story			(2)			(2)	(2)	(2)	(2)
Project Manager	Kenneth Wills	X		(2)			(2)	(2)	(2)	(2)
Term Trader	Scott Morales	X		(2)			(2)	(2)	(2)	(2)
Term Trader	John Spratley	X		(2)			(2)	(2)	(2)	(2)
Asset Manager	Bryan Mitchell			(2)	(2)	(2)				

Notes:
(1) Authority to make changes to transactions including entering transactions related to loss adjustments and full/partial requirements customers.(2) Authority to direct a transaction.

APPENDIX J
ACCOUNTING AND TAX



APPENDIX K
EMPLOYEE ACKNOWLEDGMENT

I have been provided a copy of the Southern Company Energy Trading Risk Management Policy (RMP) and have had an opportunity to read and familiarize myself with its contents and understand the requirements that apply to my position.

I understand that the officers and Board of Directors of SCS place a very high priority on each employee adhering to the requirements, policies, and procedures described in the RMP and on the accurate tracking and reporting of levels and types of risks as described in the RMP.

I agree to comply with the policies, requirements, and procedures of the RMP as all or portions of the RMP apply to my position. I do not have any questions regarding or need to clarify any matters contained in the RMP. I understand that failure to comply with the RMP or associated or related policies can result in disciplinary actions up to and including termination of employment.

_____

Printed Name

_____

Signature

Date: _____ ____, 200_

APPENDIX L
DEFINITIONS

Allowances	An authorization to emit chemical pollutants, including but not limited to sulfur dioxide, nitrous oxide, or green house gases. These are usually traded in over-the-counter markets via brokers with one allowance permitting the emission of one ton of the pollutant.
Approved Business Objectives	Those business objective defined in Appendix A which have been approved.
Approved Commodity	Those commodities listed in Appendix B which have been approved.
Authorities	All applicable limitations imposed on SCG RMP trading activities, and shall include, but not necessarily be limited to, authorized trading limits, daily loss exposure limits, maximum approved value at risk, income limits, and term limits.
Authorized Individuals	Employees whose position may involve: (1) the authority (or appearance of authority) to directly bind the Company to agreements with third parties; and/or (2) the authority (or appearance of authority), acting through its various brokers and other representatives, to the Company to exchange-traded futures and option contracts.
Approved Risk Management Instruments	Those instruments listed in Appendix C which have been approved.
Authorized Trading Limit	The levels set out in Appendix H. Such levels are expressed in dollars that establish boundaries for maximum value at risk due to changes in market prices.
Credit Policy	Southern Company Energy Trading Credit Risk Management Policy
Daily Portfolio Value	The net present value on a mark-to-market basis of yet to be performed transactions from all approved portfolios.
Financial Instruments	Futures, forwards, options, swaps, and other derivative or financial risk management transactions entered into to hedge price risks.
Forwards	An agreement to buy or sell a quantity of a product, at an agreed price, on a given date, with a specific counterparty. Forwards are typically trading in the over-the-counter (OTC) markets.
Futures	An agreement to buy or sell a quantity of a product, at an agreed price, on a given date, traded on an exchange, and cleared by a clearinghouse.
Hedging Strategy	A trading strategy intended to reduce risk.
Illiquid Market	A market characterized by wide bid/offer spreads, lack of transparency, and large movements in price after any sizable deal.

Mark to Market (MTM)	The value of a financial instrument, or risk book of such instruments, at current market rates, or prices of the underlying commodity.
Market Positions	Positions taken that are readily liquidated at a readily observable and transparent price.
Net Open Position	The sum of all open positions for the approved commodities on an equivalent basis.
Open Position	The difference between long positions and short positions in any given risk book.
Option	An instrument which provides the holder the right, but not the obligation, to sell to (or buy from) the option seller the underlying commodity at a specified price and time.
Originator	The lead individual responsible for negotiating the transaction with the counterparty.
P&L	Profit and loss
Premises	Southern Company Generation business office located in Birmingham, Alabama.
Products	Financial instruments and related transactions for approved commodities as dictated by usage.
Risk Book	The official record in which details of all transactions are maintained for valuing, monitoring, managing, and reporting said risk.
RMP	Risk Management Policy
Separation Protocol	The separation of SPC functions from the Southern Operating Companies (Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company) including information sharing and a separation of personnel in order to comply with a Federal Energy Regulatory Commission (FERC) Order.
SCS	Southern Company Services, Inc.
SPC	Southern Power Company
Swaps	An agreement to exchange net future cash flows.
Structured Transaction	Any negotiated transaction not readily traded in the market and the price of which is not easily validated.
Transactions	Futures, forwards, options, swaps, or other instruments conducted over-the-counter or via organized exchanges including long- and short-term agreements involving approved commodities or financial instruments.

Value at Risk (VaR)	The expected loss that will be incurred on the portfolio with a given level of confidence over a specified holding period, based on the distribution of price changes over a given historical observation period. (This is not an estimate of worst possible loss.)

Risk Management for Fuel and Wholesale Energy

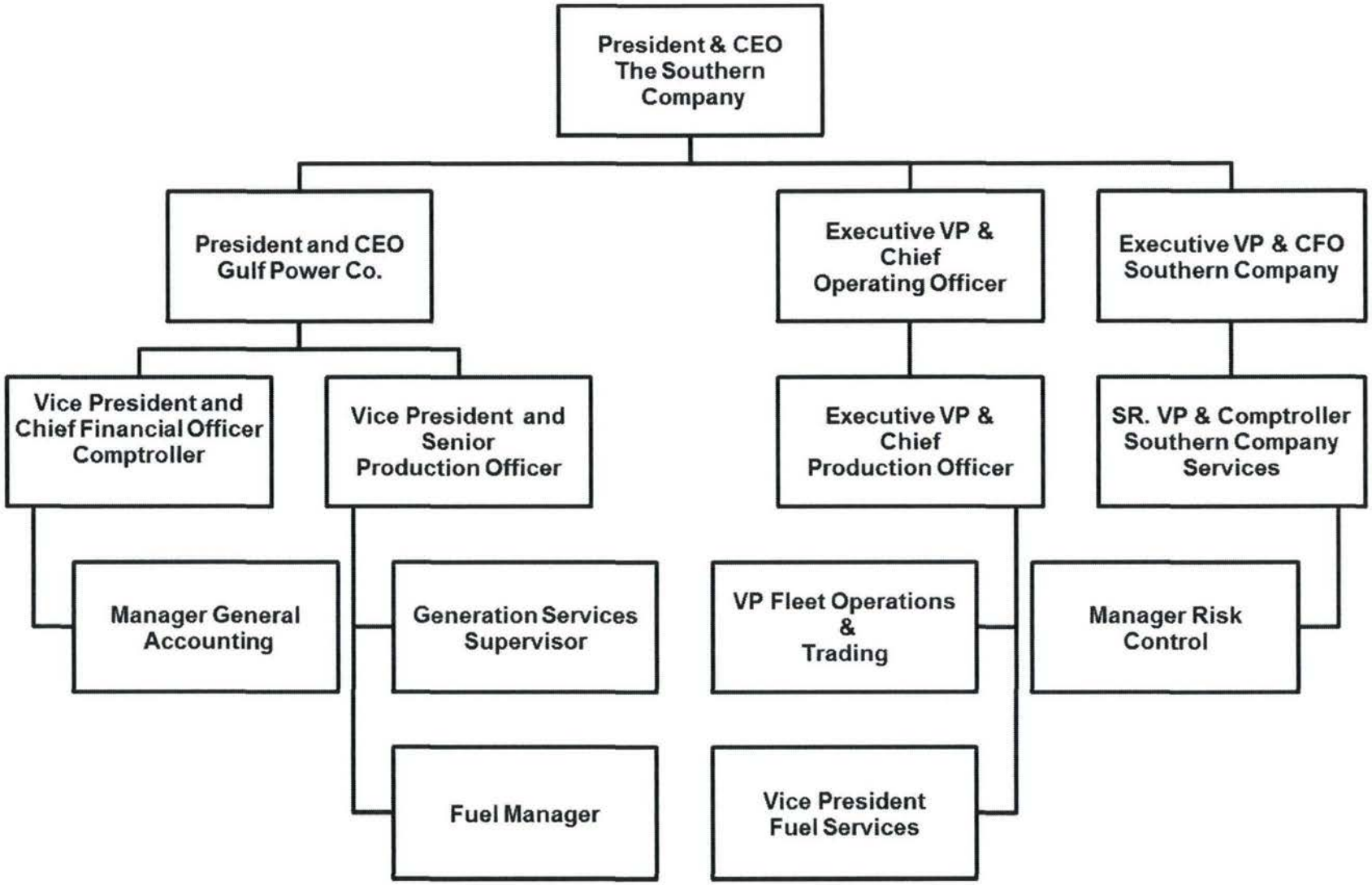


EXHIBIT NO. RWD-1

TABLE OF CONTENTS

FUEL AND PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

TITLE	DESCRIPTION	PAGE
Schedule 1	Calculation of Fuel and Purchased Power Actual True-up	2
Schedule CCA-1	Calculation of Capacity Actual True-up	3
Schedule CCA-2	Calculation of Capacity Over/(Under) Recovery	4
Schedule CCA-3	Calculation of Interest Provision on Capacity Over/(Under) Recovery	5
Schedule CCA-4	Capacity Costs	6
Appendix 1	Schedules A1 through A9 and A12 January 2012 through December 2012	8

41
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 40
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION R.W. Dodd - RWD-1

Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2012 - DECEMBER 2012

1.	Estimated over/(under)-recovery for the period January 2012 - December 2012 (Schedule E-1B, Line 6 + 7 + 8, filed August 1, 2012) approved in FPSC Order No. PSC-12-0664-FOF-EI issued on December 21, 2012)	$ 66,160,565
2.	Actual over/(under)-recovery for the period January 2012 - December 2012 (December 2012 Schedule A-2, page 2 of 3, "Period-to-Date", Lines 7 + 8 + 12, included in Appendix 1)	56,826,870
3.	Amount to be refunded/(recovered) in the January 2014 - December 2014 projection period (Line 2 - Line 1)	$ (9,333,695)

Schedule CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2012 - DECEMBER 2012

1. Estimated over/(under)-recovery for the period January 2012 - December 2012 (Schedule CCE-1a, line 1, filed August 1, 2012 and approved in FPSC Order No. PSC-12-0664-FOF-EI issued on December 21, 2012)	$	(592,654)
2. Actual over/(under)-recovery for the period January 2012 - December 2012 (Schedule CCA-2, Line 10 + 11 + 14)		(489,878)
3. Amount to be refunded/(recovered) in the January 2014 - December 2014 projection period (Line 2 - Line 1)	$	102,776

SCHEDULE CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2012 - DECEMBER 2012

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	IIC Payments / (Receipts) ($)	780,945	148,604	263,389	7,143	1,194	(3,562)	(5,502)	(8,163)	367,266	(87,886)	56,157	(144,044)	1,377,541
2.	Other Capacity Payments / (Receipts)	1,598,449	1,584,591	1,487,018	1,477,131	2,070,759	7,643,985	8,266,469	7,144,861	6,755,384	1,978,232	1,978,232	1,872,323	43,857,434
3.	Transmission Revenue ($)	(13,672)	(3,001)	(2,974)	(15,199)	29,633	(15,213)	(15,793)	(489)	(11,945)	(9,503)	(10,738)	(5,836)	(74,730)
4.	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	2,365,722	1,730,194	1,747,433	1,469,075	2,101,586	7,625,210	8,245,174	7,136,209	7,110,705	1,880,843	2,025,651	1,722,443	45,160,245
5.	Jurisdictional %	0.9644582	0.9644582	0.9644582	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
6.	Total Jurisdictional Recovery Amount (Line 4 * 5) ($)	2,281,640	1,668,700	1,685,325	1,418,737	2,029,574	7,363,929	7,962,650	6,891,684	6,867,054	1,816,395	1,956,241	1,663,423	43,605,352
7.	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	2,436,198	2,301,245	2,457,200	2,462,425	3,181,664	3,377,012	3,809,312	3,540,355	3,170,259	2,714,094	2,343,389	2,862,745	34,655,898
8.	True-Up Provision ($)	699,759	699,759	699,759	699,759	699,759	699,759	699,759	699,759	699,759	699,759	699,759	699,757	8,397,106
9.	Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	3,135,957	3,001,004	3,156,959	3,162,184	3,881,423	4,076,771	4,509,071	4,240,114	3,870,018	3,413,853	3,043,148	3,562,502	43,053,004
10.	Over/(Under) Recovery (Line 9 - 6) ($)	854,317	1,332,304	1,471,634	1,743,447	1,851,849	(3,287,158)	(3,453,579)	(2,651,570)	(2,997,036)	1,597,458	1,086,907	1,899,079	(552,348)
11.	Interest Provision ($)	512	707	655	891	1,167	1,154	725	239	(136)	(276)	(279)	(127)	5,232
12	Beginning Balance True-Up & Interest Provision ($)	8,044,076	8,199,146	8,832,398	9,604,928	10,649,507	11,802,764	7,874,239	3,721,626	370,536	(3,326,395)	(2,428,972)	(2,042,103)	8,044,076
13.	True-Up Collected/(Refunded) ($)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,759)	(699,757)	(8,397,106)
14.	Adjustment	0	0	0	0	0	57,238	0	0	0	0	0	0	57,238
15	End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) ($)	8,199,146	8,832,398	9,604,928	10,649,507	11,802,764	7,874,239	3,721,626	370,536	(3,326,395)	(2,428,972)	(2,042,103)	(842,908)	(842,908)
	Average Monthly Interest Rate	0.0063%	0.0083%	0.0071%	0.0088%	0.0104%	0.0117%	0.0125%	0.0117%	0.0092%	0.0096%	0.0125%	0.0088%	
	Annual Rate 0.03%	0.12%	0.08%	0.09%	0.12%	0.13%	0.15%	0.15%	0.13%	0.09%	0.14%	0.16%	0.05%	
	Average Annual Rate	0.075%	0.100%	0.085%	0.105%	0.125%	0.140%	0.150%	0.140%	0.110%	0.115%	0.150%	0.105%	

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2012 - DECEMBER 2012

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1 Beginning True-Up Amount ($)	8,044,076	8,199,146	8,832,398	9,604,928	10,649,507	11,802,784	7,874,239	3,721,626	370,538	(3,326,395)	(2,428,972)	(2,042,103)	
2. Ending True-Up Amount Before Interest ($)	8,198,634	8,831,691	9,604,273	10,648,616	11,801,597	7,930,323	3,720,901	370,297	(3,326,258)	(2,428,894)	(2,041,822)	(842,779)	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	16,242,710	17,030,838	18,436,671	20,253,543	22,451,104	19,733,087	11,595,140	4,091,924	(2,955,722)	(5,755,089)	(4,470,794)	(2,884,882)	
4. Average True-Up Amount ($)	8,121,355	8,515,419	9,218,335	10,126,772	11,225,552	9,866,544	5,797,570	2,045,962	(1,477,861)	(2,877,545)	(2,235,397)	(1,442,441)	
5. Interest Rate - First Day of Reporting Business Month	0.03%	0.12%	0.08%	0.09%	0.12%	0.13%	0.15%	0.15%	0.13%	0.09%	0.14%	0.16%	
6. Interest Rate - First Day of Subsequent Business Month	0.12%	0.08%	0.09%	0.12%	0.13%	0.15%	0.15%	0.13%	0.09%	0.14%	0.16%	0.05%	
7 Total Interest Rate (Lines 5 + 6)	0.15%	0.20%	0.17%	0.21%	0.25%	0.28%	0.30%	0.28%	0.22%	0.23%	0.30%	0.21%	
8. Average Interest Rate	0.075%	0.100%	0.085%	0.105%	0.125%	0.140%	0.150%	0.140%	0.110%	0.115%	0.150%	0.105%	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.0063%	0.0083%	0.0071%	0.0088%	0.0104%	0.0117%	0.0125%	0.0117%	0.0092%	0.0096%	0.0125%	0.0088%	
10. Interest Provision For the Month (Lines 4 X 9) ($)	512	707	655	891	1,167	1,154	725	239	(136)	(276)	(279)	(127)	5,232

Gulf Power Company — **Schedule CCA - 4**

2012 Capacity Contracts — **Page 1 of 2**

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs (Confidential)			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other (Confidential)			
Alabama Electric Cooperative	5/26/2012	8/16/2012	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2012	11/9/2012	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.

(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs

2012

Contract	January MW	January $	February MW	February $	March MW	March $	April MW	April $	May MW	May $ [1]	June MW	June $
Southern Intercompany Interchange	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0.0	5,692	0.0	0
PPAs												
Coral Power,LLC												
Southern Power Company												
Shell Energy N.A. (U.S.), LP												
Other												
Alabama Electric Cooperative	0.0	0	0.0	0	0.0	0	0.0	0				
South Carolina Electric & Gas									0.0	0	0.0	0
South Carolina PSA												
Total		2,379,394		1,733,195		1,750,407		1,484,274		2,071,953		7,640,423

(1) May Southern Intercompany Interchange reserve sharing charge consists of prior month true up only

DOCUMENT NUMBER-DATE
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Gulf Power Company
2012 Capacity Contracts

Schedule CCA - 4
Page 2 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs (Confidential)			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other (Confidential)			
Alabama Electric Cooperative	5/26/2012	8/16/2012	Other
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2012	11/9/2012	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs

2012 Contract	July MW	July $	August MW	August $	September MW	September $	October MW	October $	November MW	November $	December MW	December $	Total $
Southern Intercompany Interchange	0.0	0	0.0	0	57.0	371,149	(116.5)	(84,799)	165.6	63,041	(22.5)	(140,794)	1,436,250
PPAs													
Coral Power,LLC													
Southern Power Company													
Shell Energy N.A. (U.S.), LP													
Total PPAs													43,857,433
Other													
Alabama Electric Cooperative					0.0	0	0.0	0	0.0	0	0.0	0	(6,863)
South Carolina Electric & Gas											0.0	0	(13,166)
South Carolina PSA													(38,679)
Total		8,260,967		7,136,698		7,122,650		1,890,346		2,036,389		1,728,279	45,234,975

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Revised Page 7 of 209

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

JANUARY 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	27,133,652	43,492,756	(16,359,104)	(37.61)	709,328,000	962,779,000	(253,451,000)	(26.32)	3.8253	4.5174	(0.69)	(15.32)
2	Hedging Settlement Costs (A2)	2,673,650	0	2,673,650	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	5,513	0	5,513	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	29,812,815	43,492,756	(13,679,941)	(31.45)	709,328,000	962,779,000	(253,451,000)	(26.32)	4.2030	4.5174	(0.31)	(6.96)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,240,742	5,511,000	7,729,742	140.26	759,245,654	137,175,000	622,070,654	453.49	1.7439	4.0175	(2.27)	(56.59)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	640,289	0	640,289	100.00	21,022,000	0	21,022,000	100.00	3.0458	0.0000	3.05	0.00
12	TOTAL COST OF PURCHASED POWER	13,881,031	5,511,000	8,370,031	151.88	780,267,654	137,175,000	643,092,654	468.81	1.7790	4.0175	(2.24)	(55.72)
13	Total Available MWH (Line 5 + Line 12)	43,693,846	49,003,756	(5,309,910)	(10.84)	1,489,595,654	1,099,954,000	389,641,654	35.42				
14	Fuel Cost of Economy Sales (A6)	(132,343)	(507,000)	374,657	(73.90)	(5,928,849)	(13,779,000)	7,850,151	(56.97)	(2.2322)	(3.6795)	1.45	39.33
15	Gain on Economy Sales (A6)	(10,975)	(69,000)	58,025	(84.09)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(9,381,152)	(1,777,000)	(7,604,152)	427.92	(626,562,145)	(47,557,000)	(579,005,145)	1,217.50	(1.4972)	(3.7366)	2.24	59.93
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(9,524,470)	(2,353,000)	(7,171,470)	304.78	(632,490,994)	(61,336,000)	(571,154,994)	931.19	(1.5059)	(3.8362)	2.33	60.75
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	34,169,376	46,650,756	(12,481,380)	(26.75)	857,104,660	1,038,618,000	(181,513,340)	(17.48)	3.9866	4.4916	(0.51)	(11.24)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	60,441	100,747	(40,306)	(40.01)	1,516,115	2,243,000	(726,885)	(32.41)	3.9866	4.4916	(0.51)	(11.24)
22	T & D Losses *	2,932,953	2,446,754	486,199	19.87	73,570,277	54,474,000	19,096,277	35.06	3.9866	4.4916	(0.51)	(11.24)
23	TERRITORIAL KWH SALES	34,169,376	46,650,756	(12,481,380)	(26.75)	782,018,268	981,901,000	(199,882,732)	(20.36)	4.3694	4.7511	(0.38)	(8.03)
24	Wholesale KWH Sales	1,236,179	1,622,420	(386,241)	(23.81)	28,291,716	34,149,000	(5,857,284)	(17.15)	4.3694	4.7510	(0.38)	(8.03)
25	Jurisdictional KWH Sales	32,933,197	45,028,336	(12,095,139)	(26.86)	753,726,552	947,752,000	(194,025,448)	(20.47)	4.3694	4.7511	(0.38)	(8.03)
26	Jurisdictional Loss Multiplier	1.0007	1.0007							1.0007	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	32,956,250	45,059,856	(12,103,606)	(26.86)	753,726,552	947,752,000	(194,025,448)	(20.47)	4.3724	4.7544	(0.38)	(8.03)
28	TRUE-UP	1,004,265	1,004,265	0	0.00	753,726,552	947,752,000	(194,025,448)	(20.47)	0.1332	0.1060	0.03	25.66
29	TOTAL JURISDICTIONAL FUEL COST	33,960,515	46,064,121	(12,103,606)	(26.28)	753,726,552	947,752,000	(194,025,448)	(20.47)	4.5056	4.8604	(0.35)	(7.30)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.5088	4.8639	(0.36)	(7.30)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	753,726,552	947,752,000	(194,025,448)	(20.47)	0.0071	0.0057	0.00	24.56
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5159	4.8696	(0.35)	(7.26)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.516	4.870		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: JANUARY 2012

LINE	DESCRIPTION	REFERENCE		AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$	27,133,652
2	Fuel Related Transactions			0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7		5,513
4	Hedging Settlement Costs	Schedule A-2, Line A-5		2,673,650
5	Fuel Cost of Purchased Power	Schedule A-7		0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12		13,240,742
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9		0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7		640,289
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line		(9,524,470)
10	Total Fuel and Net Power Transactions		$	34,169,376

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2012
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	27,133,652	43,492,756	(16,359,104)	(37.61)	709,328,000	962,779,000	(253,451,000)	(26.32)	3.8253	4.5174	(0.69)	(15.32)
2	Hedging Settlement Costs (A2)	2,673,650	0	2,673,650	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	5,513	0	5,513	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	29,812,815	43,492,756	(13,679,941)	(31.45)	709,328,000	962,779,000	(253,451,000)	(26.32)	4.2030	4.5174	(0.31)	(6.96)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,240,742	5,511,000	7,729,742	140.26	759,245,654	137,175,000	622,070,654	453.49	1.7439	4.0175	(2.27)	(56.59)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	640,289	0	640,289	100.00	21,022,000	0	21,022,000	100.00	3.0458	0.0000	3.05	0.00
12	TOTAL COST OF PURCHASED POWER	13,881,031	5,511,000	8,370,031	151.88	780,267,654	137,175,000	643,092,654	468.81	1.7790	4.0175	(2.24)	(55.72)
13	Total Available MWH (Line 5 + Line 12)	43,693,846	49,003,756	(5,309,910)	(10.84)	1,489,595,654	1,099,954,000	389,641,654	35.42				
14	Fuel Cost of Economy Sales (A6)	(132,343)	(507,000)	374,657	(73.90)	(5,928,849)	(13,779,000)	7,850,151	(56.97)	(2.2322)	(3.6795)	1.45	39.33
15	Gain on Economy Sales (A6)	(10,975)	(69,000)	58,025	(84.09)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(9,381,152)	(1,777,000)	(7,604,152)	427.92	(626,562,145)	(47,557,000)	(579,005,145)	1,217.50	(1.4972)	(3.7366)	2.24	59.93
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(9,524,470)	(2,353,000)	(7,171,470)	304.78	(632,490,994)	(61,336,000)	(571,154,994)	931.19	(1.5059)	(3.8362)	2.33	60.75
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	34,169,376	46,650,756	(12,481,380)	(26.75)	857,104,660	1,038,618,000	(181,513,340)	(17.48)	3.9866	4.4916	(0.51)	(11.24)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	60,441	100,747	(40,306)	(40.01)	1,516,115	2,243,000	(726,885)	(32.41)	3.9866	4.4916	(0.51)	(11.24)
22	T & D Losses *	2,932,953	2,446,754	486,199	19.87	73,570,277	54,474,000	19,096,277	35.06	3.9866	4.4916	(0.51)	(11.24)
23	TERRITORIAL KWH SALES	34,169,376	46,650,756	(12,481,380)	(26.75)	782,018,268	981,901,000	(199,882,732)	(20.36)	4.3694	4.7511	(0.38)	(8.03)
24	Wholesale KWH Sales	1,236,179	1,622,420	(386,241)	(23.81)	28,291,716	34,149,000	(5,857,284)	(17.15)	4.3694	4.7510	(0.38)	(8.03)
25	Jurisdictional KWH Sales	32,933,197	45,028,336	(12,095,139)	(26.86)	753,726,552	947,752,000	(194,025,448)	(20.47)	4.3694	4.7511	(0.38)	(8.03)
26	Jurisdictional Loss Multiplier	1.0007	1.0007							1.0007	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	32,956,250	45,059,856	(12,103,606)	(26.86)	753,726,552	947,752,000	(194,025,448)	(20.47)	4.3724	4.7544	(0.38)	(8.03)
28	TRUE-UP	1,004,265	1,004,265	0	0.00	753,726,552	947,752,000	(194,025,448)	(20.47)	0.1332	0.1060	0.03	25.66
29	TOTAL JURISDICTIONAL FUEL COST	33,960,515	46,064,121	(12,103,606)	(26.28)	753,726,552	947,752,000	(194,025,448)	(20.47)	4.5056	4.8604	(0.35)	(7.30)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.5088	4.8639	(0.36)	(7.30)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	753,726,552	947,752,000	(194,025,448)	(20.47)	0.0071	0.0057	0.00	24.56
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5159	4.8696	(0.35)	(7.26)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.516	4.870		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	26,861,060.25	43,354,103	(16,493,042.75)	(38.04)	26,861,060.25	43,354,103	(16,493,042.75)	(38.04)
1a	Other Generation	272,591.98	138,653	133,938.98	96.60	272,591.98	138,653	133,938.98	96.60
2	Fuel Cost of Power Sold	(9,524,469.54)	(2,353,000)	(7,171,469.54)	(304.78)	(9,524,469.54)	(2,353,000)	(7,171,469.54)	(304.78)
3	Fuel Cost - Purchased Power	13,240,741.95	5,511,000	7,729,741.95	140.26	13,240,741.95	5,511,000	7,729,741.95	140.26
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	640,288.65	0	640,288.65	100.00	640,288.65	0	640,288.65	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	2,673,650.00	0	2,673,650.00	100.00	2,673,650.00	0	2,673,650.00	100.00
6	Total Fuel & Net Power Transactions	34,163,863.29	46,650,756	(12,486,892.71)	(26.77)	34,163,863.29	46,650,756	(12,486,892.71)	(26.77)
7	AdjustmentsTo Fuel Cost*	5,512.97	0	5,512.97	100.00	5,512.97	0	5,512.97	100.00
8	Adj. Total Fuel & Net Power Transactions	34,169,376.26	46,650,756	(12,481,379.74)	(26.75)	34,169,376.26	46,650,756	(12,481,379.74)	(26.75)
B.	*KWH Sales*								
1	Jurisdictional Sales	753,726,552	947,752,000	(194,025,448)	(20.47)	753,726,552	947,752,000	(194,025,448)	(20.47)
2	Non-Jurisdictional Sales	28,291,716	34,149,000	(5,857,284)	(17.15)	28,291,716	34,149,000	(5,857,284)	(17.15)
3	Total Territorial Sales	782,018,268	981,901,000	(199,882,732)	(20.36)	782,018,268	981,901,000	(199,882,732)	(20.36)
4	Juris. Sales as % of Total Terr. Sales	96.3822	96.5222	(0.1400)	(0.15)	96.3822	96.5222	(0.1400)	(0.15)

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 12 of 209

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$	*DIFFERENCE*			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	37,181,677.90	46,813,676	(9,631,997.61)	(20.58)	37,181,677.90	46,813,676	(9,631,997.61)	(20.58)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(1,004,265.42)	(1,004,265)	0.00	0.00	(1,004,265.42)	(1,004,265)	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(53,753.88)	(53,754)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	36,123,658.60	45,755,656	(9,631,997.40)	(21.05)	36,123,658.60	45,755,656	(9,631,997.40)	(21.05)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	34,169,376.26	46,650,756	(12,481,379.74)	(26.75)	34,169,376.26	46,650,756	(12,481,379.74)	(26.75)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.3822	96.5222	(0.1400)	(0.15)	96.3822	96.5222	(0.1400)	(0.15)
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0007)	32,956,249.80	45,059,856	(12,103,606.20)	(26.86)	32,956,249.80	45,059,856	(12,103,606.20)	(26.86)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,167,408.80	695,800	2,471,608.80	(355.22)	3,167,408.80	695,800	2,471,608.80	(355.22)
8	Interest Provision for the Month	756.92	(706)	1,462.92	207.21	756.92	(706)	1,462.92	207.21
9	Beginning True-Up & Interest Provision	9,928,693.69	(12,051,185)	21,979,878.69	182.39	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	1,004,265.42	1,004,265	0.00	0.00	1,004,265.42	1,004,265	0.00	0.00
11	End of Period - Total Net True-Up. Before Adjustment (C7+C8+C9+C10)	14,101,124.83	(10,351,826)	24,452,950.83	236.22	14,101,124.83	(10,351,826)	24,452,950.83	236.22
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	14,101,124.83	(10,351,826)	24,452,950.83	236.22	14,101,124.83	(10,351,826)	24,452,950.83	236.22

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

		CURRENT MONTH			
				$ *DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	9,928,693.69	(12,051,185)	21,979,878.69	(182.39)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	14,100,367.91	(10,351,120)	24,451,487.91	(236.22)
3	Total of Beginning & Ending True-Up Amts.	24,029,061.60	(22,402,305)	46,431,366.60	(207.26)
4	Average True-Up Amount	12,014,530.80	(11,201,153)	23,215,683.80	(207.26)
5	Interest Rate 1st Day of Reporting Business Month	0.03	0.03	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.12	0.12	0.0000	
7	Total (D5+D6)	0.15	0.15	0.0000	
8	Annual Average Interest Rate	0.08	0.08	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0063	0.0063	0.0000	
10	Interest Provision (D4*D9)	756.92	(706)	1,462.92	(207.21)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0007	1.0007		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	137,557	55,068	82,489	149.79	137,557	55,068	82,489	149.79
2	COAL	17,283,532	31,287,269	(14,003,737)	(44.76)	17,283,532	31,287,269	(14,003,737)	(44.76)
3	GAS	9,604,990	12,092,313	(2,487,323)	(20.57)	9,604,990	12,092,313	(2,487,323)	(20.57)
4	GAS (B.L.)	22,143	0	22,143	100.00	22,143	-	22,143	100.00
5	LANDFILL GAS	65,040	58,106	6,934	11.93	65,040	58,106	6,934	11.93
6	OIL - C.T.	20,390	0	20,390	100.00	20,390	0	20,390	100.00
7	TOTAL ($)	27,133,652	43,492,756	(16,359,104)	(37.61)	27,133,652	43,492,756	(16,359,104)	(37.61)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	312,040	606,909	(294,869)	(48.59)	312,040	606,909	(294,869)	(48.59)
10	GAS	394,973	353,630	41,343	11.69	394,973	353,630	41,343	11.69
11	LANDFILL GAS	2,238	2,240	(2)	(0.09)	2,238	2,240	(2)	(0.09)
12	OIL - C.T.	77	0	77	100.00	77	0	77	100.00
13	TOTAL (MWH)	709,328	962,779	(253,451)	(26.32)	709,328	962,779	(253,451)	(26.32)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,105	408	697	170.88	1,105	408	697	170.88
15	COAL (TONS)	154,254	284,358	(130,104)	(45.75)	154,254	284,358	(130,104)	(45.75)
16	GAS (MCF) (1)	2,776,436	2,356,622	419,814	17.81	2,776,436	2,356,622	419,814	17.81
17	OIL - C.T. (BBL)	204	0	204	100.00	204	0	204	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,487,052	6,589,929	(3,102,877)	(47.09)	3,487,052	6,589,929	(3,102,877)	(47.09)
19	GAS - Generation (1)	2,809,590	2,427,321	382,269	15.75	2,809,590	2,427,321	382,269	15.75
20	OIL - C.T.	1,185	0	1,185	100.00	1,185	0	1,185	100.00
21	TOTAL (MMBTU)	6,297,827	9,017,250	(2,719,423)	(30.16)	6,297,827	9,017,250	(2,719,423)	(30.16)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	43.99	63.04	(19.05)	(30.22)	43.99	63.04	(19.05)	(30.22)
24	GAS	55.68	36.73	18.95	51.59	55.68	36.73	18.95	51.59
25	LANDFILL GAS	0.32	0.23	0.09	39.13	0.32	0.23	0.09	39.13
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	124.49	135.01	(10.52)	(7.79)	124.49	135.01	(10.52)	(7.79)
29	COAL ($/TON)	112.05	110.03	2.02	1.84	112.05	110.03	2.02	1.84
30	GAS ($/MCF) (1)	3.37	5.07	(1.70)	(33.53)	3.37	5.07	(1.70)	(33.53)
31	OIL - C.T. ($/BBL)	99.95	0.00	99.95	100.00	99.95	0.00	99.95	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	5.00	4.76	0.24	5.04	5.00	4.76	0.24	5.04
33	GAS - Generation (1)	3.32	4.92	(1.60)	(32.52)	3.32	4.92	(1.60)	(32.52)
34	OIL - C.T.	17.21	0.00	17.21	100.00	17.21	0.00	17.21	100.00
35	TOTAL ($/MMBTU)	4.25	4.80	(0.55)	(11.46)	4.25	4.80	(0.55)	(11.46)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,175	10,858	317	2.92	11,175	10,858	317	2.92
37	GAS - Generation (1)	7,269	6,920	349	5.04	7,269	6,920	349	5.04
38	OIL - C.T.	15,390	0	15,390	100.00	15,390	0	15,390	100.00
39	TOTAL (BTU/KWH)	9,014	9,416	(402)	(4.27)	9,014	9,416	(402)	(4.27)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.59	5.16	0.43	8.33	5.59	5.16	0.43	8.33
41	GAS	2.43	3.42	(0.99)	(28.95)	2.43	3.42	(0.99)	(28.95)
42	LANDFILL GAS	2.91	2.59	0.32	12.36	2.91	2.59	0.32	12.36
43	OIL - C.T.	26.48	0.00	26.48	100.00	26.48	0.00	26.48	100.00
44	TOTAL (¢/KWH)	3.83	4.52	(0.69)	(15.27)	3.83	4.52	(0.69)	(15.27)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	12,968	27.5	99.8	54.5	13,165	Coal	7,217	11,828	170,727	838,638	6.47	116.20
2				2,355					Gas-G	29,224	1,011	29,545	87,438	3.71	2.99
3									Gas-S	1,111	1,011	1,124	3,325		2.99
4									Oil-S	61	137,918	351	6,763		110.87
5	Crist 5		75	12,510	31.8	100.0	53.7	11,783	Coal	6,368	11,575	147,410	739,928	5.91	116.19
6				5212					Gas-G	60,569	1,011	61,235	181,224	3.48	2.99
7									Gas-S	0	1,011	0	0		0.00
8									Oil-S	44	137,918	255	4,914		111.68
9	Crist 6		291	13,097	6.0	100.0	37.5	9,422	Coal	5,433	11,355	123,394	631,379	4.82	116.21
10				0					Gas-G	0	1,011	0	0	0.00	0.00
11									Gas-S	2,172	1,011	2,196	6,499		2.99
12									Oil-S	0	137,918	0	0		0.00
13	Crist 7		465	147,625	46.7	92.0	54.6	11,570	Coal	72,386	11,798	1,708,021	8,411,406	5.70	116.20
14				13,943					Gas-G	155,388	1,011	157,097	464,924	3.33	2.99
15									Gas-S	4,117	1,011	4,162	12,318		2.99
16									Oil-S	57	137,918	327	6,309		110.68
17	Scholz 1		46	(241)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	138,460	0	0		0.00
19	Scholz 2		46	(200)	(0.6)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	138,460	0	0		0.00
21	Smith 1		162	54,180	45.0	100.0	45.0	10,677	Coal	25,890	11,172	578,481	3,242,398	5.98	125.24
22									Oil-S	65	138,660	377	8,217		126.42
23	Smith 2		195	(556)	(0.4)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,660	0	0		0.00
25	Smith 3		531	365,029	92.4	99.2	92.4	7,018	Gas-G	2,523,855	1,015	2,561,713	8,598,812	2.36	3.41
26	Smith A	(2)	40	77	0.3	100.0	0.3	15,390	Oil	204	138,370	1,185	20,390	26.48	99.95
27	Other Generation			8,434									272,592	3.23	0.00
28	Perdido			2,238					Landfill Gas				65,040	2.91	0.00
29	Daniel 1	(1)	255	18,633	9.8	75.9	63.6	11,100	Coal	9,315	11,102	206,823	817,953	4.39	87.81
30									Oil-S	867	139,236	5,071	109,846		126.70
31	Daniel 2	(1)	255	54,024	28.5	99.7	65.6	9,963	Coal	27,646	9,735	538,263	2,427,691	4.49	87.81
32									Oil-S	12	139,236	70	1,508		125.67
33	Total		2,436	709,328	39.1	95.7	54.9	9,014				6,297,827	26,959,513	3.80	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	168,752	
N/A	Daniel Coal Inventory Adjustment	9,446	
	Recoverable Fuel	27,133,652	3.83

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	977	1,226	(249)	(20.31)	977	1,226	(249)	(20.31)
3	UNIT COST ($/BBL)	131.96	135.18	(3.22)	(2.38)	131.96	135.18	(3.22)	(2.38)
4	AMOUNT ($)	128,921	165,728	(36,807)	(22.21)	128,921	165,728	(36,807)	(22.21)
5	*BURNED :*								
6	UNITS (BBL)	1,133	408	725	177.70	1,133	408	725	177.70
7	UNIT COST ($/BBL)	124.50	134.97	(10.47)	(7.76)	124.50	134.97	(10.47)	(7.76)
8	AMOUNT ($)	141,056	55,068	85,988	156.15	141,056	55,068	85,988	156.15
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,232	16,124	(10,892)	(67.55)	5,232	16,124	(10,892)	(67.55)
11	UNIT COST ($/BBL)	119.84	46.98	72.86	155.09	119.84	46.98	72.86	155.09
12	AMOUNT ($)	627,022	757,452	(130,430)	(17.22)	627,022	757,452	(130,430)	(17.22)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	129,149	239,500	(110,351)	(46.08)	129,149	239,500	(110,351)	(46.08)
16	UNIT COST ($/TON)	120.85	116.65	4.20	3.60	120.85	116.65	4.20	3.60
17	AMOUNT ($)	15,607,934	27,937,580	(12,329,646)	(44.13)	15,607,934	27,937,580	(12,329,646)	(44.13)
18	*BURNED :*								
19	UNITS (TONS)	154,254	284,358	(130,104)	(45.75)	154,254	284,358	(130,104)	(45.75)
20	UNIT COST ($/TON)	110.98	110.03	0.95	0.86	110.98	110.03	0.95	0.86
21	AMOUNT ($)	17,118,839	31,287,269	(14,168,430)	(45.28)	17,118,839	31,287,269	(14,168,430)	(45.28)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	876,244	862,881	13,363	1.55	876,244	862,881	13,363	1.55
24	UNIT COST ($/TON)	105.81	106.33	(0.52)	(0.49)	105.81	106.33	(0.52)	(0.49)
25	AMOUNT ($)	92,712,937	91,751,242	961,695	1.05	92,712,937	91,751,242	961,695	1.05
26	DAYS SUPPLY	42	42	0	0.00	42	42	0	0.00
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,791,301	2,427,321	363,980	15.00	2,791,301	2,427,321	363,980	15.00
29	UNIT COST ($/MMBTU)	3.18	4.92	(1.74)	(35.37)	3.18	4.92	(1.74)	(35.37)
30	AMOUNT ($)	8,866,061	11,953,660	(3,087,599)	(25.83)	8,866,061	11,953,660	(3,087,599)	(25.83)
31	*BURNED :*								
32	UNITS (MMBTU)	2,817,072	2,427,321	389,751	16.06	2,817,072	2,427,321	389,751	16.06
33	UNIT COST ($/MMBTU)	3.32	4.92	(1.60)	(32.52)	3.32	4.92	(1.60)	(32.52)
34	AMOUNT ($)	9,354,541	11,953,660	(2,599,119)	(21.74)	9,354,541	11,953,660	(2,599,119)	(21.74)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	1,003,807	0	1,003,807	100.00	1,003,807	0	1,003,807	100.00
37	UNIT COST ($/MMBTU)	3.36	0.00	3.36	100.00	3.36	0.00	3.36	100.00
38	AMOUNT ($)	3,369,444	0	3,369,444	100.00	3,369,444	0	3,369,444	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	0	0	0	0.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	AMOUNT ($)	0	0	0	0.00	0	0	0	0.00
43	*BURNED :*								
44	UNITS (BBL)	204	0	204	100.00	204	0	204	100.00
45	UNIT COST ($/BBL)	99.95	0.00	99.95	100.00	99.95	0.00	99.95	100.00
46	AMOUNT ($)	20,390	0	20,390	100.00	20,390	0	20,390	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,622	7,143	(521)	(7.29)	6,622	7,143	(521)	(7.29)
49	UNIT COST ($/BBL)	99.97	97.52	2.45	2.51	99.97	97.52	2.45	2.51
50	AMOUNT ($)	662,004	696,578	(34,574)	(4.96)	662,004	696,578	(34,574)	(4.96)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	c / KWH FUEL COST	c / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		47,557,000	0	47,557,000	3.74	4.10	1,777,000	1,948,000
2	Various	Economy Sales	13,779,000	0	13,779,000	3.68	4.10	507,000	565,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	69,000	0
4	TOTAL ESTIMATED SALES		61,336,000	0	61,336,000	3.84	4.10	2,353,000	2,513,000
	ACTUAL								
5	Southern Company Interchange		420,082,277	0	420,082,277	2.26	2.40	9,513,183	10,066,438
6	A.E.C.	External	465,029	0	465,029	2.48	3.17	11,540	14,763
7	AECI	External	21,060	0	21,060	2.07	3.20	436	674
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	9,099	0	9,099	2.15	3.46	195	315
13	CARGILE	External	942,398	0	942,398	2.09	2.83	19,700	26,634
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	97,034	0	97,034	2.09	2.80	2,027	2,716
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	817,395	0	817,395	1.99	2.70	16,270	22,075
19	EAGLE EN	External	61,681	0	61,681	2.48	3.41	1,531	2,105
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	233,976	0	233,976	2.41	4.48	5,633	10,490
23	FPC	External	48,745	0	48,745	4.21	6.80	2,050	3,315
24	FPL	External	0	0	0	0.00	0.00	0	0
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	124,076	0	124,076	2.24	2.83	2,774	3,509
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MORGAN	External	25,154	0	25,154	2.54	3.23	639	814
31	NCEMC	External	0	0	0	0.00	0.00	0	0
32	NCMPA1	External	1,690	0	1,690	2.68	3.80	45	64
33	NRG	External	0	0	0	0.00	0.00	0	0
34	OPC	External	124,849	0	124,849	2.47	3.50	3,082	4,374
35	ORLANDO	External	0	0	0	0.00	0.00	0	0
36	PJM	External	1,332,163	0	1,332,163	1.92	3.32	25,633	44,185
37	REMC	External	0	0	0	0.00	0.00	0	0
38	SCE&G	External	625,537	0	625,537	3.07	4.01	19,212	25,062
39	SEC	External	28,274	0	28,274	2.14	2.88	605	815
40	SEPA	External	50,174	0	50,174	2.12	3.05	1,066	1,530
41	SHELL	External	0	0	0	0.00	0.00	0	0
42	TAL	External	0	0	0	0.00	0.00	0	0
43	TEA	External	756,996	0	756,996	2.08	3.01	15,719	22,772
44	TECO	External	1,040	0	1,040	2.27	3.40	24	35
45	TENASKA	External	0	0	0	0.00	0.00	0	0
46	TVA	External	162,479	0	162,479	2.56	4.05	4,162	6,587
47	WRI	External	0	0	0	0.00	0.00	0	0
48	Less: Flow-Thru Energy		(5,928,849)	0	(5,928,849)	2.23	2.23	(132,031)	(132,031)
49	SEPA		1,858,560	1,858,560	0	0.00	0.00	0	0
50	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	10,975	10,975
51	Other transactions including adj.		210,550,157	173,280,011	37,270,146	0.00	0.00	0	0
52	TOTAL ACTUAL SALES		632,490,994	175,138,571	457,352,423	1.51	1.60	9,524,470	10,127,242
53	Difference in Amount		571,154,994	175,138,571	396,016,423	(2.33)	(2.50)	7,171,470	7,614,242
54	Difference in Percent		931.19	0.00	645.65	(60.68)	(60.98)	304.78	302.99

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 50

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		47,557,000	0	47,557,000	3.74	4.10	1,777,000	1,948,000
2	Various	Economy Sales	13,779,000	0	13,779,000	3.68	4.10	507,000	565,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	69,000	0
4	TOTAL ESTIMATED SALES		61,336,000	0	61,336,000	3.84	4.10	2,353,000	2,513,000
	ACTUAL								
5	Southern Company Interchange		420,082,277	0	420,082,277	2.26	2.40	9,513,183	10,066,438
6	A.E.C.	External	465,029	0	465,029	2.48	3.17	11,540	14,763
7	AECI	External	21,060	0	21,060	2.07	3.20	436	674
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	9,099	0	9,099	2.15	3.46	195	315
13	CARGILE	External	942,398	0	942,398	2.09	2.83	19,700	26,634
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	97,034	0	97,034	2.09	2.80	2,027	2,716
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	817,395	0	817,395	1.99	2.70	16,270	22,075
19	EAGLE EN	External	61,681	0	61,681	2.48	3.41	1,531	2,105
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	233,976	0	233,976	2.41	4.48	5,633	10,490
23	FPC	External	48,745	0	48,745	4.21	6.80	2,050	3,315
24	FPL	External	0	0	0	0.00	0.00	0	0
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	124,076	0	124,076	2.24	2.83	2,774	3,509
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MORGAN	External	25,154	0	25,154	2.54	3.23	639	814
31	NCEMC	External	0	0	0	0.00	0.00	0	0
32	NCMPA1	External	1,690	0	1,690	2.68	3.80	45	64
33	NRG	External	0	0	0	0.00	0.00	0	0
34	OPC	External	124,849	0	124,849	2.47	3.50	3,082	4,374
35	ORLANDO	External	0	0	0	0.00	0.00	0	0
36	PJM	External	1,332,163	0	1,332,163	1.92	3.32	25,633	44,185
37	REMC	External	0	0	0	0.00	0.00	0	0
38	SCE&G	External	625,537	0	625,537	3.07	4.01	19,212	25,062
39	SEC	External	28,274	0	28,274	2.14	2.88	605	815
40	SEPA	External	50,174	0	50,174	2.12	3.05	1,066	1,530
41	SHELL	External	0	0	0	0.00	0.00	0	0
42	TAL	External	0	0	0	0.00	0.00	0	0
43	TEA	External	756,996	0	756,996	2.08	3.01	15,719	22,772
44	TECO	External	1,040	0	1,040	2.27	3.40	24	35
45	TENASKA	External	0	0	0	0.00	0.00	0	0
46	TVA	External	162,479	0	162,479	2.56	4.05	4,162	6,587
47	WRI	External	0	0	0	0.00	0.00	0	0
48	Less: Flow-Thru Energy		(5,928,849)	0	(5,928,849)	2.23	2.23	(132,031)	(132,031)
49	SEPA		1,858,560	1,858,560	0	0.00	0.00	0	0
50	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	10,975	10,975
51	Other transactions including adj.		210,550,157	173,280,011	37,270,146	0.00	0.00	0	0
52	TOTAL ACTUAL SALES		632,490,994	175,138,571	457,352,423	1.51	1.60	9,524,470	10,127,242
53	Difference in Amount		571,154,994	175,138,571	396,016,423	(2.33)	(2.50)	7,171,470	7,614,242
54	Difference in Percent		931.19	0.00	645.65	(60.68)	(60.98)	304.78	302.99

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 50

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JANUARY 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

CURRENT MONTH

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	2,371,000	0	0	0	7.38	7.38	175,029
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	18,601,000	0	0	0	2.49	2.49	463,957
6	International Paper	COG 1	50,000	0	0	0	2.61	2.61	1,303
7	TOTAL		21,022,000	0	0	0	3.05	3.05	640,289

PERIOD-TO-DATE

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	2,371,000	0	0	0	7.38	7.38	175,029
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	18,601,000	0	0	0	2.49	2.49	463,957
6	International Paper	COG 1	50,000	0	0	0	2.61	2.61	1,303
7	TOTAL		21,022,000	0	0	0	3.05	3.05	640,289

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 21 of 209

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2012

	(1)	CURRENT MONTH (2)	(3)	(4)	PERIOD - TO - DATE (5)	(6)	(7)
	PURCHASED FROM	TOTAL KWH PURCHASED	TRANS. COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.	TOTAL KWH PURCHASED	TRANS. COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	131,000,000	4.00	5,238,000	131,000,000	4.00	5,238,000
2	Economy Energy	4,514,000	4.08	184,000	4,514,000	4.08	184,000
3	Other Purchases	1,661,000	5.36	89,000	1,661,000	5.36	89,000
4	TOTAL ESTIMATED PURCHASES	137,175,000	4.02	5,511,000	137,175,000	4.02	5,511,000
	ACTUAL						
5	Southern Company Interchange	26,224,868	2.11	553,471	26,224,868	2.11	553,471
6	Non-Associated Companies	28,406,321	3.31	939,547	28,406,321	3.31	939,547
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	495,625,000	2.40	11,877,289	495,625,000	2.40	11,877,289
9	Other Wheeled Energy	48,642,000	0.00	N/A	48,642,000	0.00	N/A
10	Other Transactions	166,276,314	0.01	16,219	166,276,314	0.01	16,219
11	Less: Flow-Thru Energy	(5,928,849)	2.46	(145,784)	(5,928,849)	2.46	(145,784)
12	TOTAL ACTUAL PURCHASES	759,245,654	1.74	13,240,742	759,245,654	1.74	13,240,742
13	Difference in Amount	622,070,654	(2.28)	7,729,742	622,070,654	(2.28)	7,729,742
14	Difference in Percent	453.49	(56.72)	140.26	453.49	(56.72)	140.26

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 22 of 209

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448											791,448
SUBTOTAL					$ 791,448		$ -		$ -		$ -		$ -		$ -	$ 791,448
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449											1,598,449
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)											(10,503)
SUBTOTAL					$ 1,587,946		$ -		$ -		$ -		$ -		$ -	$ 1,587,946
TOTAL					**$ 2,379,394**		**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	**$ 2,379,394**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													791,448
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 791,448
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													1,598,449
2 Other Confidential Agreements	Other	Varies	Varies													(10,503)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,587,946
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 2,379,394

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 24 of 209

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: FEBRUARY 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 21,319,222
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	1,855
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,994,705
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	14,424,165
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	509,232
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(10,800,645)
10	Total Fuel and Net Power Transactions		$ 28,448,534

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	21,319,222	40,863,218	(19,543,996)	(47.83)	616,103,000	885,106,000	(269,003,000)	(30.39)	3.4603	4.6168	(1.16)	(25.05)
2	Hedging Settlement Costs (A2)	2,994,705	0	2,994,705	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	1,855	0	1,855	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	24,315,782	40,863,218	(16,547,436)	(40.49)	616,103,000	885,106,000	(269,003,000)	(30.39)	3.9467	4.6168	(0.67)	(14.51)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	14,424,165	3,731,000	10,693,165	286.60	867,772,744	93,227,000	774,545,744	830.82	1.6622	4.0021	(2.34)	(58.47)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	509,232	0	509,232	100.00	17,497,000	0	17,497,000	100.00	2.9104	0.0000	2.91	0.00
12	TOTAL COST OF PURCHASED POWER	14,933,397	3,731,000	11,202,397	300.25	885,269,744	93,227,000	792,042,744	849.59	1.6869	4.0021	(2.32)	(57.85)
13	Total Available MWH (Line 5 + Line 12)	39,249,179	44,594,218	(5,345,039)	(11.99)	1,501,372,744	978,333,000	523,039,744	53.46				
14	Fuel Cost of Economy Sales (A6)	(125,231)	(571,000)	445,769	(78.07)	(5,706,407)	(16,136,000)	10,429,593	(64.64)	(2.1946)	(3.5387)	1.34	37.98
15	Gain on Economy Sales (A6)	(37,761)	(78,000)	40,239	(51.59)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(10,637,653)	(2,397,000)	(8,240,653)	343.79	(730,373,853)	(67,919,000)	(662,454,853)	975.36	(1.4565)	(3.5292)	2.07	58.73
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(10,800,645)	(3,046,000)	(7,754,645)	254.58	(736,080,260)	(84,055,000)	(652,025,260)	775.71	(1.4673)	(3.6238)	2.16	59.51
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	28,448,534	41,548,218	(13,099,684)	(31.53)	765,292,484	894,278,000	(128,985,516)	(14.42)	3.7173	4.6460	(0.93)	(19.99)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	56,043	73,500	(17,457)	(23.75)	1,507,628	1,582,000	(74,372)	(4.70)	3.7173	4.6460	(0.93)	(19.99)
22	T & D Losses *	716,876	1,871,548	(1,154,672)	(61.70)	19,284,861	40,283,000	(20,998,139)	(52.13)	3.7173	4.6460	(0.93)	(19.99)
23	TERRITORIAL KWH SALES	28,448,534	41,548,218	(13,099,684)	(31.53)	744,499,995	852,413,000	(107,913,005)	(12.66)	3.8212	4.8742	(1.05)	(21.60)
24	Wholesale KWH Sales	958,659	1,461,584	(502,925)	(34.41)	25,088,497	29,986,000	(4,897,503)	(16.33)	3.8211	4.8742	(1.05)	(21.61)
25	Jurisdictional KWH Sales	27,489,875	40,086,634	(12,596,759)	(31.42)	719,411,498	822,427,000	(103,015,502)	(12.53)	3.8212	4.8742	(1.05)	(21.60)
26	Jurisdictional Loss Multiplier	1.0007	1.0007							1.0007	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	27,509,118	40,114,695	(12,605,577)	(31.42)	719,411,498	822,427,000	(103,015,502)	(12.53)	3.8238	4.8776	(1.05)	(21.60)
28	TRUE-UP	1,004,265	1,004,265	0	0.00	719,411,498	822,427,000	(103,015,502)	(12.53)	0.1396	0.1221	0.02	14.33
29	TOTAL JURISDICTIONAL FUEL COST	28,513,383	41,118,960	(12,605,577)	(30.66)	719,411,498	822,427,000	(103,015,502)	(12.53)	3.9634	4.9997	(1.04)	(20.73)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9663	5.0033	(1.04)	(20.73)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	719,411,498	822,427,000	(103,015,502)	(12.53)	0.0075	0.0065	0.00	15.38
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9738	5.0098	(1.04)	(20.68)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.974	5.010		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 26 of 209

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	48,452,874	84,355,974	(35,903,100)	(42.56)	1,325,431,000	1,847,885,000	(522,454,000)	(28.27)	3.6556	4.5650	(0.91)	(19.92)
2	Hedging Settlement Costs (A2)	5,668,355	0	5,668,355	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	7,368	0	7,368	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	54,128,597	84,355,974	(30,227,377)	(35.83)	1,325,431,000	1,847,885,000	(522,454,000)	(28.27)	4.0838	4.5650	(0.48)	(10.54)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	27,664,907	9,242,000	18,422,907	199.34	1,627,018,398	230,402,000	1,396,616,398	606.17	1.7003	4.0112	(2.31)	(57.61)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	1,149,521	0	1,149,521	100.00	38,519,000	0	38,519,000	100.00	2.9843	0.0000	2.98	0.00
12	TOTAL COST OF PURCHASED POWER	28,814,428	9,242,000	19,572,428	211.78	1,665,537,398	230,402,000	1,435,135,398	622.88	1.7300	4.0112	(2.28)	(56.87)
13	Total Available MWH (Line 5 + Line 12)	82,943,025	93,597,974	(10,654,949)	(11.38)	2,990,968,398	2,078,287,000	912,681,398	43.92				
14	Fuel Cost of Economy Sales (A6)	(257,574)	(1,078,000)	820,426	(76.11)	(11,635,256)	(29,915,000)	18,279,744	(61.11)	(2.2137)	(3.6035)	1.39	38.57
15	Gain on Economy Sales (A6)	(48,736)	(147,000)	98,264	(66.85)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(20,018,805)	(4,174,000)	(15,844,805)	379.61	(1,356,935,998)	(115,476,000)	(1,241,459,998)	1,075.08	(1.4753)	(3.6146)	2.14	59.18
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(20,325,115)	(5,399,000)	(14,926,115)	276.46	(1,368,571,254)	(145,391,000)	(1,223,180,254)	841.30	(1.4851)	(3.7134)	2.23	60.01
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	62,617,910	88,198,974	(25,581,064)	(29.00)	1,622,397,144	1,932,896,000	(310,498,856)	(16.06)	3.8596	4.5630	(0.70)	(15.42)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	116,704	174,535	(57,831)	(33.13)	3,023,743	3,825,000	(801,257)	(20.95)	3.8596	4.5630	(0.70)	(15.42)
22	T & D Losses *	3,583,837	4,323,762	(739,925)	(17.11)	92,856,138	94,757,000	(1,901,862)	(2.01)	3.8596	4.5630	(0.70)	(15.42)
23	TERRITORIAL KWH SALES	62,617,910	88,198,974	(25,581,064)	(29.00)	1,526,516,263	1,834,314,000	(307,795,737)	(16.78)	4.1020	4.8083	(0.71)	(14.69)
24	Wholesale KWH Sales	2,194,838	3,084,004	(889,166)	(28.83)	53,380,213	64,135,000	(10,754,787)	(16.77)	4.1117	4.8086	(0.70)	(14.49)
25	Jurisdictional KWH Sales	60,423,072	85,114,970	(24,691,898)	(29.01)	1,473,136,050	1,770,179,000	(297,040,950)	(16.78)	4.1017	4.8083	(0.71)	(14.70)
26	Jurisdictional Loss Multiplier	1.0007	1.0007							1.0007	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	60,465,368	85,174,551	(24,709,183)	(29.01)	1,473,136,050	1,770,179,000	(297,040,950)	(16.78)	4.1045	4.8116	(0.71)	(14.70)
28	TRUE-UP	2,008,530	2,008,530	0	0.00	1,473,136,050	1,770,179,000	(297,040,950)	(16.78)	0.1363	0.1135	0.02	20.09
29	TOTAL JURISDICTIONAL FUEL COST	62,473,898	87,183,081	(24,709,183)	(28.34)	1,473,136,050	1,770,179,000	(297,040,950)	(16.78)	4.2408	4.9251	(0.68)	(13.89)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2439	4.9286	(0.68)	(13.89)
32	GPIF Reward / (Penalty)	107,586	107,586	0	0.00	1,473,136,050	1,770,179,000	(297,040,950)	(16.78)	0.0073	0.0061	0.00	19.67
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2512	4.9347	(0.68)	(13.85)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.251	4.935		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 27 of 209

SCHEDULE A-2
PAGE 1 OF 3

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	21,154,308.11	40,733,486	(19,579,177.89)	(48.07)	48,015,368.36	84,087,589	(36,072,220.64)	(42.90)
1a	Other Generation	164,913.96	129,732	35,181.96	27.12	437,505.94	268,385	169,120.94	63.01
2	Fuel Cost of Power Sold	(10,800,644.65)	(3,046,000)	(7,754,644.65)	(254.58)	(20,325,114.19)	(5,399,000)	(14,926,114.19)	(276.46)
3	Fuel Cost - Purchased Power	14,424,164.75	3,731,000	10,693,164.75	286.60	27,664,906.70	9,242,000	18,422,906.70	199.34
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	509,232.07	0	509,232.07	100.00	1,149,520.72	0	1,149,520.72	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	2,994,705.00	0	2,994,705.00	100.00	5,668,355.00	0	5,668,355.00	100.00
6	Total Fuel & Net Power Transactions	28,446,679.24	41,548,218	(13,101,538.76)	(31.53)	62,610,542.53	88,198,974	(25,588,431.47)	(29.01)
7	AdjustmentsTo Fuel Cost*	1,854.66	0	1,854.66	100.00	7,367.63	0	7,367.63	100.00
8	Adj. Total Fuel & Net Power Transactions	28,448,533.90	41,548,218	(13,099,684.10)	(31.53)	62,617,910.16	88,198,974	(25,581,063.84)	(29.00)
B.	*KWH Sales*								
1	Jurisdictional Sales	719,411,498	822,427,000	(103,015,502)	(12.53)	1,473,138,050	1,770,179,000	(297,040,950)	(16.78)
2	Non-Jurisdictional Sales	25,088,497	29,986,000	(4,897,503)	(16.33)	53,380,213	64,135,000	(10,754,787)	(16.77)
3	Total Territorial Sales	744,499,995	852,413,000	(107,913,005)	(12.66)	1,526,518,263	1,834,314,000	(307,795,737)	(16.78)
4	Juris. Sales as % of Total Terr. Sales	96.6302	96.4822	0.1480	0.15	96.5031	96.5036	(0.0005)	0.00

(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

4

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	34,597,402.54	40,623,318	(6,025,915.28)	(14.83)	71,779,080.44	87,436,993	(15,657,912.89)	(17.91)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(1,004,265.42)	(1,004,265)	0.00	0.00	(2,008,530.84)	(2,008,531)	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(107,507.76)	(107,508)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	33,539,383.24	39,565,299	(6,025,915.76)	(15.23)	69,663,041.84	85,320,955	(15,657,913.16)	(18.35)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	28,448,533.90	41,548,218	(13,099,684.10)	(31.53)	62,617,910.16	88,198,974	(25,581,063.84)	(29.00)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.6302	96.4822	0.1480	0.15	96.5031	96.5036	(0.0005)	0.00
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0007)	27,509,118.12	40,114,695	(12,605,576.88)	(31.42)	60,465,367.92	85,174,551	(24,709,183.08)	(29.01)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	6,030,265.12	(549,396)	6,579,661.12	1,197.62	9,197,673.92	146,404	9,051,269.92	(6,182.39)
8	Interest Provision for the Month	1,462.33	(840)	2,302.33	274.09	2,219.25	(1,547)	3,766.25	243.46
9	Beginning True-Up & Interest Provision	14,101,124.83	(10,351,826)	24,452,950.83	236.22	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	1,004,265.42	1,004,265	0.00	0.00	2,008,530.84	2,008,531	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	21,137,117.70	(9,897,797)	31,034,914.70	313.55	21,137,117.70	(9,897,797)	31,034,914.70	313.55
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	21,137,117.70	(9,897,797)	31,034,914.70	313.55	21,137,117.70	(9,897,797)	31,034,914.70	313.55

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 29 of 209

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	14,101,124.83	(10,351,826)	24,452,950.83	(236.22)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	21,135,655.37	(9,896,957)	31,032,612.37	(313.56)
3	Total of Beginning & Ending True-Up Amts.	35,236,780.20	(20,248,783)	55,485,563.20	(274.02)
4	Average True-Up Amount	17,618,390.10	(10,124,392)	27,742,782.10	(274.02)
	Interest Rate				
5	1st Day of Reporting Business Month	0.12	0.12	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.08	0.08	0.0000	
7	Total (D5+D6)	0.20	0.20	0.0000	
8	Annual Average Interest Rate	0.10	0.10	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0083	0.0083	0.0000	
10	Interest Provision (D4*D9)	1,462.33	(840)	2,302.33	(274.09)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0007	1.0007		

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 30 of 209

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	47,780	55,211	(7,431)	(13.46)	185,337	110,279	75,058	68.06
2	COAL	11,792,632	30,018,649	(18,226,017)	(60.72)	29,076,164	61,305,919	(32,229,755)	(52.57)
3	GAS	9,405,132	10,734,988	(1,329,856)	(12.39)	19,010,122	22,827,301	(3,817,179)	(16.72)
4	GAS (B.L.)	-	0	0	0.00	22,143	-	22,143	100.00
5	LANDFILL GAS	57,993	54,370	3,623	6.66	123,033	112,476	10,557	9.39
6	OIL - C.T.	15,685	0	15,685	100.00	36,075	0	36,075	100.00
7	TOTAL ($)	21,319,222	40,863,218	(19,543,996)	(47.83)	48,452,874	84,355,974	(35,903,100)	(42.56)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	203,530	591,056	(387,526)	(65.57)	515,570	1,197,965	(682,395)	(56.96)
10	GAS	410,431	291,954	118,477	40.58	805,404	645,584	159,820	24.76
11	LANDFILL GAS	2,092	2,096	(4)	(0.19)	4,330	4,336	(6)	(0.14)
12	OIL - C.T.	50	0	50	100.00	127	0	127	100.00
13	TOTAL (MWH)	616,103	885,106	(269,003)	(30.39)	1,325,431	1,847,885	(522,454)	(28.27)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	404	408	(4)	(0.98)	1,509	816	693	84.95
15	COAL (TONS)	102,643	278,231	(175,588)	(63.11)	256,897	562,589	(305,692)	(54.34)
16	GAS (MCF) (1)	3,005,377	2,078,372	927,005	44.60	5,781,813	4,434,995	1,346,818	30.37
17	OIL - C.T. (BBL)	157	0	157	100.00	361	0	361	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,368,388	6,417,011	(4,048,623)	(63.09)	5,855,440	13,006,940	(7,151,500)	(54.98)
19	GAS - Generation (1)	3,049,389	2,140,723	908,666	42.45	5,858,979	4,568,043	1,290,936	28.26
20	OIL - C.T.	912	0	912	100.00	2,097	0	2,097	100.00
21	TOTAL (MMBTU)	5,418,689	8,557,734	(3,139,045)	(36.68)	11,716,516	17,574,983	(5,858,467)	(33.33)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	33.04	66.78	(33.74)	(50.52)	38.90	64.83	(25.93)	(40.00)
24	GAS	66.61	32.98	33.63	101.97	60.76	34.94	25.82	73.90
25	LANDFILL GAS	0.34	0.24	0.10	41.67	0.33	0.23	0.10	43.48
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	118.27	135.36	(17.09)	(12.63)	122.82	135.19	(12.37)	(9.15)
29	COAL ($/TON)	114.89	107.89	7.00	6.49	113.18	108.97	4.21	3.86
30	GAS ($/MCF) (1)	3.07	5.10	(2.03)	(39.80)	3.22	5.09	(1.87)	(36.74)
31	OIL - C.T. ($/BBL)	99.90	0.00	99.90	100.00	99.93	0.00	99.93	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	5.00	4.69	0.31	6.61	5.00	4.72	0.28	5.93
33	GAS - Generation (1)	3.03	4.95	(1.92)	(38.79)	3.17	4.94	(1.77)	(35.83)
34	OIL - C.T.	17.20	0.00	17.20	100.00	17.20	0.00	17.20	100.00
35	TOTAL ($/MMBTU)	3.89	4.75	(0.86)	(18.11)	4.09	4.78	(0.69)	(14.44)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,637	10,857	780	7.18	11,357	10,858	499	4.60
37	GAS - Generation (1)	7,522	7,400	122	1.65	7,398	7,137	261	3.66
38	OIL - C.T.	18,240	0	18,240	100.00	16,512	0	16,512	100.00
39	TOTAL (BTU/KWH)	8,898	9,721	(823)	(8.47)	8,960	9,562	(602)	(6.30)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.82	5.09	0.73	14.34	5.68	5.13	0.55	10.72
41	GAS	2.29	3.68	(1.39)	(37.77)	2.36	3.54	(1.18)	(33.33)
42	LANDFILL GAS	2.77	2.59	0.18	6.95	2.84	2.59	0.25	9.65
43	OIL - C.T.	31.37	0.00	31.37	100.00	28.41	0.00	28.41	100.00
44	TOTAL (¢/KWH)	3.46	4.62	(1.16)	(25.11)	3.66	4.57	(0.91)	(19.91)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(922)	(1.8)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,013	0	0	0.00	0.00
3									Gas-S	0	1,013	0	0		0.00
4									Oil-S	0	137,918	0	0		0.00
5	Crist 5		75	26,701	55.7	100.0	55.8	11,134	Coal	12,888	11,533	297,285	1,412,472	5.29	109.60
6				2,398					Gas-G	26,462	1,013	26,806	75,749	3.16	2.86
7									Gas-S	0	1,013	0	0		0.00
8									Oil-S	210	137,918	1,218	23,463		111.73
9	Crist 6		291	(3,642)	(1.8)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,013	0	0	0.00	0.00
11									Gas-S	0	1,013	0	0		0.00
12									Oil-S	0	137,918	0	0		0.00
13	Crist 7		465	133,422	55.2	100.0	55.2	11,391	Coal	65,223	11,651	1,519,820	7,147,900	5.36	109.59
14				45,164					Gas-G	508,115	1,013	514,721	1,454,525	3.22	2.86
15									Gas-S	0	1,013	0	0		0.00
16									Oil-S	72	137,918	416	8,013		111.29
17	Scholz 1		46	(191)	(0.6)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	138,460	0	0		0.00
19	Scholz 2		46	(206)	(0.6)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	138,460	0	0		0.00
21	Smith 1		162	50,839	45.1	100.0	45.1	10,780	Coal	24,500	11,185	548,069	3,210,422	6.31	131.04
22									Oil-S	122	168,066	860	16,305		133.65
23	Smith 2		195	(472)	(0.3)	86.1	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	168,066	0	0		0.00
25	Smith 3		531	357,829	96.8	100.0	96.8	7,009	Gas-G	2,470,800	1,015	2,507,862	7,709,944	2.15	3.12
26	Smith A	(2)	40	50	0.2	100.0	66.4	18,240	Oil	157	138,370	912	15,685	31.37	99.90
27	Other Generation			5,040									164,914	3.27	0.00
28	Perdido			2,092					Landfill Gas				57,993	2.77	0.00
29	Daniel 1	(1)	255	(1,171)	(0.7)	100.0	0.0	0	Coal	32	11,243	720	2,844	0.00	88.88
30									Oil-S	0	139,278	0	0		0.00
31	Daniel 2	(1)	255	(828)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	139,278	0	0		0.00
33	Total		2,436	616,103	36.3	98.9	37.4	8,898				5,418,689	21,300,229	3.46	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	23,052	
	Recoverable Fuel	21,319,222	3.46

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	444	1,226	(782)	(63.78)	1,421	2,452	(1,031)	(42.05)
3	UNIT COST ($/BBL)	133.59	135.18	(1.59)	(1.18)	132.47	135.18	(2.71)	(2.00)
4	AMOUNT ($)	59,313	165,728	(106,415)	(64.21)	188,234	331,456	(143,222)	(43.21)
5	*BURNED:*								
6	UNITS (BBL)	431	408	23	5.64	1,563	816	747	91.54
7	UNIT COST ($/BBL)	119.03	135.32	(16.29)	(12.04)	123.07	135.15	(12.08)	(8.94)
8	AMOUNT ($)	51,300	55,211	(3,911)	(7.08)	192,356	110,279	82,077	74.43
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,246	16,942	(11,696)	(69.04)	5,246	16,942	(11,696)	(69.04)
11	UNIT COST ($/BBL)	121.05	51.23	69.82	136.29	121.05	51.23	69.82	136.29
12	AMOUNT ($)	635,035	867,969	(232,934)	(26.84)	635,035	867,969	(232,934)	(26.84)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	133,108	214,891	(81,783)	(38.06)	262,257	454,391	(192,134)	(42.28)
16	UNIT COST ($/TON)	107.25	110.87	(3.62)	(3.27)	113.95	113.92	0.03	0.03
17	AMOUNT ($)	14,275,784	23,824,967	(9,549,183)	(40.08)	29,883,718	51,762,547	(21,878,829)	(42.27)
18	*BURNED:*								
19	UNITS (TONS)	102,643	278,231	(175,588)	(63.11)	256,897	562,589	(305,692)	(54.34)
20	UNIT COST ($/TON)	114.70	107.89	6.81	6.31	112.47	108.97	3.50	3.21
21	AMOUNT ($)	11,773,639	30,018,649	(18,245,010)	(60.78)	28,892,478	61,305,918	(32,413,440)	(52.87)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	906,708	799,541	107,167	13.40	906,708	799,541	107,167	13.40
24	UNIT COST ($/TON)	105.01	107.01	(2.00)	(1.87)	105.01	107.01	(2.00)	(1.87)
25	AMOUNT ($)	95,215,081	85,557,560	9,657,521	11.29	95,215,081	85,557,560	9,657,521	11.29
26	DAYS SUPPLY	44	39	5	12.82	44	39	5	12.82
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	3,049,443	2,140,723	908,720	42.45	5,840,744	4,568,043	1,272,701	27.86
29	UNIT COST ($/MMBTU)	2.94	4.95	(2.01)	(40.61)	3.05	4.94	(1.89)	(38.26)
30	AMOUNT ($)	8,956,787	10,605,256	(1,648,469)	(15.54)	17,822,848	22,558,916	(4,736,068)	(20.99)
31	*BURNED:*								
32	UNITS (MMBTU)	3,049,443	2,140,723	908,720	42.45	5,866,515	4,568,043	1,298,472	28.43
33	UNIT COST ($/MMBTU)	3.03	4.95	(1.92)	(38.79)	3.17	4.94	(1.77)	(35.83)
34	AMOUNT ($)	9,240,217	10,605,256	(1,365,039)	(12.87)	18,594,758	22,558,916	(3,964,158)	(17.57)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	1,003,807	0	1,003,807	100.00	1,003,807	0	1,003,807	100.00
37	UNIT COST ($/MMBTU)	3.07	0.00	3.07	100.00	3.07	0.00	3.07	100.00
38	AMOUNT ($)	3,086,013	0	3,086,013	100.00	3,086,013	0	3,086,013	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	0	0	0	0.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	AMOUNT ($)	0	0	0	0.00	0	0	0	0.00
43	*BURNED:*								
44	UNITS (BBL)	157	0	157	100.00	361	0	361	100.00
45	UNIT COST ($/BBL)	99.90	0.00	99.90	100.00	99.93	0.00	99.93	100.00
46	AMOUNT ($)	15,685	0	15,685	100.00	36,075	0	36,075	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,466	7,143	(677)	(9.48)	6,466	7,143	(677)	(9.48)
49	UNIT COST ($/BBL)	99.96	97.52	2.44	2.50	99 96	97.52	2.44	2.50
50	AMOUNT ($)	646,319	696,578	(50,259)	(7.22)	646,319	696,578	(50,259)	(7.22)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	TOTAL COST	TOTAL $ FOR FUEL ADJ	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		67,919,000	0	67,919,000	3.53	3.84	2,397,000	2,609,000
2	Various	Economy Sales	16,136,000	0	16,136,000	3.54	3.90	571,000	630,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	78,000	0
4	TOTAL ESTIMATED SALES		84,055,000	0	84,055,000	3.62	3.85	3,046,000	3,239,000
	ACTUAL								
5	Southern Company Interchange		502,850,759	0	502,850,759	2.14	2.36	10,762,943	11,844,373
6	A.E.C.	External	43,873	0	43,873	1.99	3.17	874	1,390
7	AECI	External	3,250	0	3,250	2.03	3.80	66	123
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	21,122	0	21,122	2.46	3.55	519	751
13	CARGILE	External	272,517	0	272,517	2.06	2.62	5,626	7,142
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	158,001	0	158,001	1.96	2.72	3,102	4,293
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	938,609	0	938,609	2.06	2.69	19,315	25,269
19	EAGLE EN	External	53,947	0	53,947	2.32	3.21	1,250	1,733
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	242,608	0	242,608	3.62	9.39	8,781	22,788
23	FPC	External	0	0	0	0.00	0.00	0	0
24	FPL	External	90,989	0	90,989	2.15	3.60	1,960	3,276
25	JARON	External	26,000	0	26,000	1.65	2.20	430	572
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	72,600	0	72,600	2.39	3.33	1,735	2,414
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MORGAN	External	207,462	0	207,462	1.89	2.58	3,915	5,353
31	NCEMC	External	6,500	0	6,500	1.80	2.89	117	188
32	NCMPA1	External	0	0	0	0.00	0.00	0	0
33	NRG	External	0	0	0	0.00	0.00	0	0
34	OPC	External	88,714	0	88,714	1.80	2.86	1,597	2,537
35	ORLANDO	External	0	0	0	0.00	0.00	0	0
36	PJM	External	1,417,481	0	1,417,481	2.02	2.81	28,603	39,786
37	REMC	External	0	0	0	0.00	0.00	0	0
38	SCE&G	External	305,142	0	305,142	4.02	7.87	12,267	24,027
39	SEC	External	87,419	0	87,419	1.96	2.73	1,717	2,385
40	SEPA	External	142,271	0	142,271	2.12	3.24	3,013	4,603
41	SHELL	External	0	0	0	0.00	0.00	0	0
42	TAL	External	12,350	0	12,350	2.15	3.10	265	383
43	TEA	External	1,136,448	0	1,136,448	2.02	2.82	22,907	32,067
44	TECO	External	7,474	0	7,474	1.60	2.50	119	187
45	TENASKA	External	0	0	0	0.00	0.00	0	0
46	TVA	External	293,630	0	293,630	1.90	2.82	5,576	8,275
47	WRI	External	78,000	0	78,000	1.89	2.35	1,474	1,833
48	Less: Flow-Thru Energy		(5,706,407)	0	(5,706,407)	2.20	2.20	(125,290)	(125,290)
49	SEPA		1,487,816	1,487,816	0	0.00	0.00	0	0
50	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	37,761	37,761
51	Other transactions including adj.		231,741,685	187,496,171	44,245,514	0.00	0.00	0	0
52	TOTAL ACTUAL SALES		736,080,260	188,983,987	547,096,273	1.47	1.62	10,800,645	11,910,456
53	Difference in Amount		652,025,260	188,983,987	463,041,273	(2.15)	(2.23)	7,754,645	8,671,456
54	Difference in Percent		775.71	0.00	550.88	(59.39)	(57.92)	254.58	267.72

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 50

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		115,476,000	0	115,476,000	3.61	3.95	4,174,000	4,557,000
2	Various	Economy Sales	29,915,000	0	29,915,000	3.60	3.99	1,078,000	1,195,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	147,000	0
4	TOTAL ESTIMATED SALES		145,391,000	0	145,391,000	3.71	3.96	5,399,000	5,752,000
	ACTUAL								
5	Southern Company Interchange		922,933,036	0	922,933,036	2.20	2.37	20,276,126	21,910,811
6	A.E.C.	External	508,902	0	508,902	2.44	3.17	12,414	16,153
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	30,221	0	30,221	2.36	3.53	714	1,066
13	CARGILE	External	1,214,915	0	1,214,915	2.08	2.78	25,326	33,776
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	255,035	0	255,035	2.01	2.75	5,129	7,009
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	1,756,004	0	1,756,004	2.03	2.70	35,585	47,344
19	EAGLE EN	External	115,628	0	115,628	2.41	3.32	2,782	3,838
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	476,584	0	476,584	3.02	6.98	14,415	33,278
23	FPC	External	48,745	0	48,745	4.21	6.80	2,050	3,315
24	FPL	External	90,989	0	90,989	2.15	3.60	1,960	3,276
25	JARON	External	26,000	0	26,000	1.65	2.20	430	572
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	196,676	0	196,676	2.29	3.01	4,509	5,923
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MORGAN	External	232,616	0	232,616	1.96	2.65	4,554	6,167
31	NCEMC	External	6,500	0	6,500	1.80	2.89	117	188
32	NCMPA1	External	1,690	0	1,690	2.68	3.80	45	64
33	NRG	External	0	0	0	0.00	0.00	0	0
34	OPC	External	213,563	0	213,563	2.19	3.24	4,678	6,911
35	ORLANDO	External	0	0	0	0.00	0.00	0	0
36	PJM	External	2,749,644	0	2,749,644	1.97	3.05	54,236	83,972
37	REMC	External	0	0	0	0.00	0.00	0	0
38	SCE&G	External	930,679	0	930,679	3.38	5.27	31,479	49,089
39	SEC	External	115,693	0	115,693	2.01	2.77	2,322	3,200
40	SEPA	External	192,445	0	192,445	2.12	3.19	4,079	6,133
41	SHELL	External	0	0	0	0.00	0.00	0	0
42	TAL	External	12,350	0	12,350	2.15	3.10	265	383
43	TEA	External	1,893,444	0	1,893,444	2.04	2.90	38,626	54,839
44	TECO	External	8,514	0	8,514	1.68	2.61	143	222
45	TENASKA	External	0	0	0	0.00	0.00	0	0
46	TVA	External	456,109	0	456,109	2.13	3.26	9,736	14,862
47	WRI	External	78,000	0	78,000	1.89	2.35	1,474	1,833
48	Less: Flow-Thru Energy		(11,635,256)	0	(11,635,256)	2.21	2.21	(257,321)	(257,321)
49	SEPA		3,346,376	3,346,376	0	0.00	0.00	0	0
50	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	48,736	48,736
51	Other transactions including adj.		442,291,842	360,776,182	81,515,660	0.00	0.00	0	0
52	TOTAL ACTUAL SALES		1,368,571,254	364,122,558	1,004,448,696	1.49	1.61	20,325,115	22,037,698
53	Difference in Amount		1,223,180,254	364,122,558	859,057,696	(2.22)	(2.35)	14,926,115	16,285,698
54	Difference in Percent		841.30	0.00	590.86	(59.84)	(59.34)	276.46	283.13

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 50

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: FEBRUARY 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

CURRENT MONTH

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	1,855,000	0	0	0	7.38	7.38	136,894
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	15,627,000	0	0	0	2.38	2.38	371,945
6	International Paper	COG 1	15,000	0	0	0	2.62	2.62	393
7	TOTAL		17,497,000	0	0	0	2.91	2.91	509,232

PERIOD-TO-DATE

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.38	7.38	311,923
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	34,228,000	0	0	0	2.44	2.44	835,902
6	International Paper	COG 1	65,000	0	0	0	2.61	2.61	1,695
7	TOTAL		38,519,000	0	0	0	2.98	2.98	1,149,521

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	85,453,000	3.98	3,404,000	216,453,000	3.99	8,642,000
2	Economy Energy	5,636,000	3.76	212,000	10,150,000	3.90	396,000
3	Other Purchases	2,138,000	5.38	115,000	3,799,000	5.37	204,000
4	TOTAL ESTIMATED PURCHASES	93,227,000	4.00	3,731,000	230,402,000	4.01	9,242,000
	ACTUAL						
5	Southern Company Interchange	78,477,254	2.45	1,926,515	104,702,122	2.37	2,479,986
6	Non-Associated Companies	25,899,279	2.91	753,104	54,305,600	3.12	1,692,651
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	533,979,000	2.22	11,865,582	1,029,604,000	2.31	23,742,871
9	Other Wheeled Energy	68,015,000	0.00	N/A	116,657,000	0.00	N/A
10	Other Transactions	167,108,618	0.01	17,278	333,384,932	0.01	33,497
11	Less: Flow-Thru Energy	(5,706,407)	2.42	(138,314)	(11,635,256)	2.44	(284,098)
12	TOTAL ACTUAL PURCHASES	867,772,744	1.66	14,424,165	1,627,018,398	1.70	27,664,907
13	Difference in Amount	774,545,744	(2.34)	10,693,165	1,396,616,398	(2.31)	18,422,907
14	Difference in Percent	830.82	(58.50)	286.60	606.17	(57.61)	199.34

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 38 of 209

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312									943,760
SUBTOTAL					$ 791,448		$ 152,312		$ -		$ -		$ -		$ -	$ 943,760
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591									3,183,040
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)									(14,211)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ -		$ -		$ -		$ -	$ 3,168,829
TOTAL					$ 2,379,394		$ 1,733,195		$ -		$ -		$ -		$ -	$ 4,112,589

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													943,760
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 943,760
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													3,183,040
2 Other Confidential Agreements	Other	Varies	Varies													(14,211)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 3,168,829
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 4,112,589

Docket No. 130001-EI
2012 Final True-up Filing
Exhibit RWD-1, Page 40 of 209

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	24,856,944	42,386,409	(17,529,465)	(41.36)	746,221,000	971,158,000	(224,937,000)	(23.16)	3.3310	4.3645	(1.03)	(23.68)
2	Hedging Settlement Costs (A2)	3,514,941	0	3,514,941	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	6,357	0	6,357	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	28,378,242	42,386,409	(14,008,167)	(33.05)	746,221,000	971,158,000	(224,937,000)	(23.16)	3.8029	4.3645	(0.56)	(12.87)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,168,157	1,608,000	11,560,157	718.92	909,973,041	41,942,000	868,031,041	2,069.60	1.4471	3.8339	(2.39)	(62.26)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	418,489	0	418,489	100.00	17,330,000	0	17,330,000	100.00	2.4148	0.0000	2.41	0.00
12	TOTAL COST OF PURCHASED POWER	13,586,646	1,608,000	11,978,646	744.94	927,303,041	41,942,000	885,361,041	2,110.92	1.4652	3.8339	(2.37)	(61.78)
13	Total Available MWH (Line 5 + Line 12)	41,964,888	43,994,409	(2,029,521)	(4.61)	1,673,524,041	1,013,100,000	660,424,041	65.19				
14	Fuel Cost of Economy Sales (A6)	(55,323)	(418,000)	362,677	(86.76)	(2,688,997)	(12,033,000)	9,344,003	(77.65)	(2.0574)	(3.4738)	1.42	40.77
15	Gain on Economy Sales (A6)	13,490	(60,000)	73,490	(122.48)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(13,087,857)	(3,474,000)	(9,613,857)	276.74	(823,656,952)	(98,676,000)	(724,980,952)	734.71	(1.5890)	(3.5206)	1.93	54.87
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(13,129,690)	(3,952,000)	(9,177,690)	232.23	(826,345,949)	(110,709,000)	(715,636,949)	646.41	(1.5889)	(3.5697)	1.98	55.49
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	28,835,198	40,042,409	(11,207,211)	(27.99)	847,178,092	902,391,000	(55,212,908)	(6.12)	3.4037	4.4374	(1.03)	(23.30)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	58,872	79,651	(20,779)	(26.09)	1,729,636	1,795,000	(65,364)	(3.64)	3.4037	4.4374	(1.03)	(23.30)
22	T & D Losses *	1,550,820	1,815,118	(264,298)	(14.56)	45,562,760	40,905,000	4,657,760	11.39	3.4037	4.4374	(1.03)	(23.30)
23	TERRITORIAL KWH SALES	28,835,198	40,042,409	(11,207,211)	(27.99)	799,885,696	859,691,000	(59,805,304)	(6.96)	3.6049	4.6578	(1.05)	(22.61)
24	Wholesale KWH Sales	931,290	1,343,583	(412,293)	(30.69)	25,833,913	28,846,000	(3,012,087)	(10.44)	3.6049	4.6578	(1.05)	(22.61)
25	Jurisdictional KWH Sales	27,903,908	38,698,826	(10,794,918)	(27.89)	774,051,783	830,845,000	(56,793,217)	(6.84)	3.6049	4.6578	(1.05)	(22.61)
26	Jurisdictional Loss Multiplier	1.0007	1.0007							1.0007	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	27,923,441	38,725,915	(10,802,474)	(27.89)	774,051,783	830,845,000	(56,793,217)	(6.84)	3.6074	4.6610	(1.05)	(22.60)
28	TRUE-UP	(1,491,621)	(1,491,621)	0	0.00	774,051,783	830,845,000	(56,793,217)	(6.84)	(0.1927)	(0.1795)	(0.01)	7.35
29	TOTAL JURISDICTIONAL FUEL COST	26,431,820	37,234,294	(10,802,474)	(29.01)	774,051,783	830,845,000	(56,793,217)	(6.84)	3.4147	4.4815	(1.07)	(23.80)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.4172	4.4847	(1.07)	(23.80)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	774,051,783	830,845,000	(56,793,217)	(6.84)	0.0069	0.0065	0.00	6.15
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4241	4.4912	(1.07)	(23.76)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.424	4.491		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: MARCH 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 24,856,944
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	6,357
4	Hedging Settlement Costs	Schedule A-2, Line A-5	3,514,941
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	13,168,157
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	418,489
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(13,129,690)
10	Total Fuel and Net Power Transactions		$ 28,835,198

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	73,309,818	126,742,383	(53,432,565)	(42.16)	2,071,652,000	2,819,043,000	(747,391,000)	(26.51)	3.5387	4.4959	(0.96)	(21.29)
2	Hedging Settlement Costs (A2)	9,183,296	0	9,183,296	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	13,725	0	13,725	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	82,506,839	126,742,383	(44,235,544)	(34.90)	2,071,652,000	2,819,043,000	(747,391,000)	(26.51)	3.9827	4.4959	(0.51)	(11.41)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	40,833,064	10,850,000	29,983,064	276.34	2,536,991,439	272,344,000	2,264,647,439	831.54	1.6095	3.9839	(2.37)	(59.60)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	1,568,010	0	1,568,010	100.00	55,849,000	0	55,849,000	100.00	2.8076	0.0000	2.81	0.00
12	TOTAL COST OF PURCHASED POWER	42,401,074	10,850,000	31,551,074	290.79	2,592,840,439	272,344,000	2,320,496,439	852.05	1.6353	3.9839	(2.35)	(58.95)
13	Total Available MWH (Line 5 + Line 12)	124,907,913	137,592,383	(12,684,470)	(9.22)	4,664,492,439	3,091,387,000	1,573,105,439	50.89				
14	Fuel Cost of Economy Sales (A6)	(312,897)	(1,496,000)	1,183,103	(79.08)	(14,324,253)	(41,948,000)	27,623,747	(65.85)	(2.1844)	(3.5663)	1.38	38.75
15	Gain on Economy Sales (A6)	(35,246)	(207,000)	171,754	(82.97)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(33,106,662)	(7,648,000)	(25,458,662)	332.88	(2,180,592,950)	(214,152,000)	(1,966,440,950)	918.25	(1.5182)	(3.5713)	2.05	57.49
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(33,454,805)	(9,351,000)	(24,103,805)	257.77	(2,194,917,203)	(256,100,000)	(1,938,817,203)	757.05	(1.5242)	(3.6513)	2.13	58.26
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	91,453,108	128,241,383	(36,788,275)	(28.69)	2,469,575,236	2,835,287,000	(365,711,764)	(12.90)	3.7032	4.5230	(0.82)	(18.13)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	176,027	254,193	(78,166)	(30.75)	4,753,379	5,620,000	(866,621)	(15.42)	3.7032	4.5230	(0.82)	(18.13)
22	T & D Losses *	5,125,892	6,135,992	(1,010,100)	(16.46)	138,417,898	135,662,000	2,755,898	2.03	3.7032	4.5230	(0.82)	(18.13)
23	TERRITORIAL KWH SALES	91,453,108	128,241,383	(36,788,275)	(28.69)	2,326,403,959	2,694,005,000	(367,601,041)	(13.65)	3.9311	4.7603	(0.83)	(17.42)
24	Wholesale KWH Sales	3,126,128	4,427,587	(1,301,459)	(29.39)	79,214,126	92,981,000	(13,766,874)	(14.81)	3.9464	4.7618	(0.82)	(17.12)
25	Jurisdictional KWH Sales	88,326,980	123,813,796	(35,486,816)	(28.66)	2,247,189,833	2,601,024,000	(353,834,167)	(13.60)	3.9306	4.7602	(0.83)	(17.43)
26	Jurisdictional Loss Multiplier	1.0007	1.0007							1.0007	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	88,388,809	123,900,466	(35,511,657)	(28.66)	2,247,189,833	2,601,024,000	(353,834,167)	(13.60)	3.9333	4.7635	(0.83)	(17.43)
28	TRUE-UP	516,909	516,909	0	0.00	2,247,189,833	2,601,024,000	(353,834,167)	(13.60)	0.0230	0.0199	0.00	15.58
29	TOTAL JURISDICTIONAL FUEL COST	88,905,718	124,417,375	(35,511,657)	(28.54)	2,247,189,833	2,601,024,000	(353,834,167)	(13.60)	3.9563	4.7834	(0.83)	(17.29)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9591	4.7868	(0.83)	(17.29)
32	GPIF Reward / (Penalty)	161,379	161,379	0	0.00	2,247,189,833	2,601,024,000	(353,834,167)	(13.60)	0.0072	0.0062	0.00	16.13
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9663	4.7930	(0.83)	(17.25)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.966	4.793		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	24,623,933.35	42,247,756	(17,623,822.70)	(41.72)	72,639,301.71	126,335,345	(53,696,043.34)	(42.50)
1a	Other Generation	233,010.41	138,653	94,357.41	68.05	670,516.35	407,038	263,478.35	64.73
2	Fuel Cost of Power Sold	(13,129,690.13)	(3,952,000)	(9,177,690.13)	(232.23)	(33,454,804.32)	(9,351,000)	(24,103,804.32)	(257.77)
3	Fuel Cost - Purchased Power	13,168,156.90	1,608,000	11,560,156.90	718.92	40,833,063.60	10,850,000	29,983,063.60	276.34
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	418,489.35	0	418,489.35	100.00	1,568,010.07	0	1,568,010.07	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	3,514,941.00	0	3,514,941.00	100.00	9,183,296.00	0	9,183,296.00	100.00
6	Total Fuel & Net Power Transactions	28,828,840.88	40,042,409	(11,213,568.17)	(28.00)	91,439,383.41	128,241,383	(36,801,999.64)	(28.70)
7	AdjustmentsTo Fuel Cost*	6,357.38	0	6,357.38	100.00	13,725.01	0	13,725.01	100.00
8	Adj. Total Fuel & Net Power Transactions	28,835,198.26	40,042,409	(11,207,210.74)	(27.99)	91,453,108.42	128,241,383	(36,788,274.63)	(28.69)
B.	*KWH Sales*								
1	Jurisdictional Sales	774,051,783	830,845,000	(56,793,217)	(6.84)	2,247,189,833	2,601,024,000	(353,834,167)	(13.60)
2	Non-Jurisdictional Sales	25,833,913	28,846,000	(3,012,087)	(10.44)	79,214,126	92,981,000	(13,766,874)	(14.81)
3	Total Territorial Sales	799,885,696	859,691,000	(59,805,304)	(6.96)	2,326,403,959	2,694,005,000	(367,601,041)	(13.65)
4	Juris. Sales as % of Total Terr. Sales	96.7703	96.6446	0.1257	0.13	96.5950	96.5486	0.0464	0.05

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	35,679,934.10	38,355,959	(2,676,025.33)	(6.98)	107,459,014.54	125,792,953	(18,333,938.22)	(14.57)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	1,491,620.90	1,491,621	0.00	0.00	(516,909.94)	(516,910)	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(161,261.64)	(161,262)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	37,117,801.12	39,793,826	(2,676,024.88)	(6.72)	106,780,842.96	125,114,781	(18,333,938.04)	(14.65)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	28,835,198.26	40,042,409	(11,207,210.74)	(27.99)	91,453,108.42	128,241,383	(36,788,274.58)	(28.69)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.7703	96.6446	0.1257	0.13	96.5950	96.5486	0.0464	0.05
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0007)	27,923,440.60	38,725,915	(10,802,474.40)	(27.89)	88,388,808.52	123,900,466	(35,511,657.48)	(28.66)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	9,194,360.52	1,067,911	8,126,449.52	(760.97)	18,392,034.44	1,214,315	17,177,719.44	(1,414.60)
8	Interest Provision for the Month	1,774.18	(718)	2,492.18	347.10	3,993.43	(2,265)	6,258.43	276.31
9	Beginning True-Up & Interest Provision	21,137,117.70	(9,897,797)	31,034,914.70	313.55	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(1,491,620.90)	(1,491,621)	0.00	0.00	516,909.94	516,910	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	28,841,631.50	(10,322,225)	39,163,856.50	379.41	28,841,631.50	(10,322,225)	39,163,856.50	379.41
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	28,841,631.50	(10,322,225)	39,163,856.50	379.41	28,841,631.50	(10,322,225)	39,163,856.50	379.41

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	21,137,117.70	(9,897,797)	31,034,914.70	(313.55)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	28,839,857.32	(10,321,507)	39,161,364.32	(379.42)
3	Total of Beginning & Ending True-Up Amts.	49,976,975.02	(20,219,304)	70,196,279.02	(347.17)
4	Average True-Up Amount	24,988,487.51	(10,109,652)	35,098,139.51	(347.17)
	Interest Rate				
5	1st Day of Reporting Business Month	0.08	0.08	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.09	0.09	0.0000	
7	Total (D5+D6)	0.17	0.17	0.0000	
8	Annual Average Interest Rate	0.09	0.09	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0071	0.0071	0.0000	
10	Interest Provision (D4*D9)	1,774.18	(718)	2,492.18	(347.10)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0007	1.0007		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	118,237	55,288	62,949	113.86	303,574	165,567	138,007	83.35
2	COAL	16,003,343	32,069,310	(16,065,967)	(50.10)	45,079,507	93,375,229	(48,295,722)	(51.72)
3	GAS	8,664,629	10,203,705	(1,539,076)	(15.08)	27,674,751	33,031,006	(5,356,255)	(16.22)
4	GAS (B.L.)	1,797	0	1,797	100.00	23,940	-	23,940	100.00
5	LANDFILL GAS	61,096	58,106	2,990	5.15	184,129	170,582	13,547	7.94
6	OIL - C.T.	7,842	0	7,842	100.00	43,917	0	43,917	100.00
7	TOTAL ($)	24,856,944	42,386,409	(17,529,465)	(41.36)	73,309,818	126,742,383	(53,432,565)	(42.16)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	336,197	633,504	(297,307)	(46.93)	851,767	1,831,469	(979,702)	(53.49)
10	GAS	407,801	335,414	72,387	21.58	1,213,205	980,998	232,207	23.67
11	LANDFILL GAS	2,202	2,240	(38)	(1.70)	6,532	6,576	(44)	(0.67)
12	OIL - C.T.	21	0	21	100.00	148	0	148	100.00
13	TOTAL (MWH)	746,221	971,158	(224,937)	(23.16)	2,071,652	2,819,043	(747,391)	(26.51)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	925	408	517	126.75	2,434	1,224	1,210	98.89
15	COAL (TONS)	152,942	300,840	(147,898)	(49.16)	409,839	863,429	(453,590)	(52.53)
16	GAS (MCF) (1)	3,026,666	2,244,412	782,254	34.85	8,808,479	6,679,406	2,129,073	31.88
17	OIL - C.T. (BBL)	78	0	78	100.00	439	0	439	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,740,447	6,899,025	(3,158,578)	(45.78)	9,595,887	19,905,965	(10,310,078)	(51.79)
19	GAS - Generation (1)	3,066,483	2,311,744	754,739	32.65	8,925,462	6,879,787	2,045,675	29.73
20	OIL - C.T.	456	0	456	100.00	2,553	0	2,553	100.00
21	TOTAL (MMBTU)	6,807,386	9,210,769	(2,403,383)	(26.09)	18,523,902	26,785,752	(8,261,850)	(30.84)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	45.05	65.23	(20.18)	(30.94)	41.12	64.97	(23.85)	(36.71)
24	GAS	54.65	34.54	20.11	58.22	58.55	34.80	23.75	68.25
25	LANDFILL GAS	0.30	0.23	0.07	30.43	0.32	0.23	0.09	39.13
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	127.82	135.55	(7.73)	(5.70)	124.72	135.31	(10.59)	(7.83)
29	COAL ($/TON)	104.64	106.60	(1.96)	(1.84)	109.99	108.14	1.85	1.71
30	GAS ($/MCF) (1)	2.79	4.48	(1.69)	(37.72)	3.07	4.88	(1.81)	(37.09)
31	OIL - C.T. ($/BBL)	100.54	0.00	100.54	100.00	100.04	0.00	100.04	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.31	4.66	(0.35)	(7.51)	4.73	4.70	0.03	0.64
33	GAS - Generation (1)	2.75	4.35	(1.60)	(36.78)	3.03	4.74	(1.71)	(36.08)
34	OIL - C.T.	17.20	0.00	17.20	100.00	17.20	0.00	17.20	100.00
35	TOTAL ($/MMBTU)	3.61	4.58	(0.97)	(21.18)	3.91	4.71	(0.80)	(16.99)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,126	10,890	236	2.17	11,266	10,869	397	3.65
37	GAS - Generation (1)	7,653	6,951	702	10.10	7,484	7,074	410	5.80
38	OIL - C.T.	21,714	0	21,714	100.00	17,250	0	17,250	100.00
39	TOTAL (BTU/KWH)	9,238	9,534	(296)	(3.10)	9,060	9,552	(492)	(5.15)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.80	5.07	(0.27)	(5.33)	5.33	5.11	0.22	4.31
41	GAS	2.12	3.04	(0.92)	(30.26)	2.28	3.37	(1.09)	(32.34)
42	LANDFILL GAS	2.77	2.59	0.18	6.95	2.82	2.59	0.23	8.88
43	OIL - C.T.	37.34	0.00	37.34	100.00	29.67	0.00	29.67	100.00
44	TOTAL (¢/KWH)	3.33	4.36	(1.03)	(23.62)	3.54	4.50	(0.96)	(21.33)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	2,276	4.1	99.7	38.8	6,170	Coal	605	11,604	14,044	65,383	2.87	108.07
2				0					Gas-G	0	1,015	0	0	0.00	0.00
3									Gas-S	721	1,015	732	1,797		2.49
4									Oil-S	31	137,918	177	3,416		110.19
5	Crist 5		75	32,081	57.6	94.4	63.1	12,000	Coal	16,641	11,567	384,980	1,798,003	5.60	108.05
6				-					Gas-G	0	1,015	0	0	0.00	0.00
7									Gas-S	0	1,015	0	0		0.00
8									Oil-S	13	137,918	78	1,498		115.23
9	Crist 6		291	(3,495)	(1.6)	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,015	0	0	0.00	0.00
11									Gas-S	0	1,015	0	0		0.00
12									Oil-S	0	137,918	0	0		0.00
13	Crist 7		465	138,249	55.5	100.0	55.5	11,364	Coal	67,418	11,652	1,571,105	7,284,137	5.27	108.04
14				53,550					Gas-G	600,047	1,015	609,048	1,495,874	2.79	2.49
15									Gas-S	0	1,015	0	0		0.00
16									Oil-S	37	137,918	212	4,079		110.24
17	Scholz 1		46	(265)	(0.8)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	138,460	0	0		0.00
19	Scholz 2		46	(131)	(0.4)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	138,460	0	0		0.00
21	Smith 1		162	51,768	43.0	99.3	43.3	10,797	Coal	24,702	11,314	558,960	3,161,535	6.11	127.99
22									Oil-S	162	138,066	941	22,539		139.13
23	Smith 2		195	(445)	(0.3)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,066	0	0		0.00
25	Smith 3		531	347,117	88.0	97.6	88.5	7,080	Gas-G	2,425,898	1,013	2,457,435	6,935,745	2.00	2.86
26	Smith A	(2)	40	21	0.1	100.0	57.3	21,714	Oil	78	138,370	456	7,842	37.34	100.54
27	Other Generation			7,134									233,010	3.27	0.00
28	Perdido			2,202					Landfill Gas				61,096	2.77	0.00
29	Daniel 1	(1)	255	14,519	7.7	55.5	57.6	10,734	Coal	7,744	10,063	155,853	691,048	4.76	89.24
30									Oil-S	391	138,855	2,278	49,615		126.89
31	Daniel 2	(1)	255	101,640	53.6	99.3	73.6	10,325	Coal	50,739	10,341	1,049,384	4,527,729	4.45	89.24
32									Oil-S	292	138,855	1,703	37,090		127.02
33	Total		2,436	746,221	41.2	82.6	50.6	9,238				6,807,386	26,381,436	3.54	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	206,714	
(4,778)	Crist Flyover Adj	(535,670)	
(10,130)	Smith Flyover Adj	(1,290,635)	
	Crist Coal Consumption PM Adj	181,178	
	Smith Coal Consumption PM Adj	(82,020)	
	Recoverable Fuel	24,856,944	3.33

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	178	1,226	(1,048)	(85.48)	1,599	3,678	(2,079)	(56.53)
3	UNIT COST ($/BBL)	142.81	135.18	7.63	5.64	133.62	135.18	(1.56)	(1.15)
4	AMOUNT ($)	25,421	165,728	(140,307)	(84.66)	213,655	497,184	(283,529)	(57.03)
5	*BURNED:*								
6	UNITS (BBL)	964	408	556	136.27	2,527	1,224	1,303	106.45
7	UNIT COST ($/BBL)	128.07	135.51	(7.44)	(5.49)	124.98	135.27	(10.29)	(7.61)
8	AMOUNT ($)	123,460	55,288	68,172	123.30	315,816	165,567	150,249	90.75
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,459	17,760	(13,301)	(74.89)	4,459	17,760	(13,301)	(74.89)
11	UNIT COST ($/BBL)	120.43	55.09	65.34	118.61	120.43	55.09	65.34	118.61
12	AMOUNT ($)	536,996	978,409	(441,413)	(45.12)	536,996	978,409	(441,413)	(45.12)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	164,906	212,000	(47,094)	(22.21)	427,163	666,391	(239,228)	(35.90)
16	UNIT COST ($/TON)	104.09	111.21	(7.12)	(6.40)	110.14	113.05	(2.91)	(2.57)
17	AMOUNT ($)	17,164,468	23,575,868	(6,411,400)	(27.19)	47,048,186	75,338,415	(28,290,229)	(37.55)
18	*BURNED:*								
19	UNITS (TONS)	152,942	300,840	(147,898)	(49.16)	409,839	863,429	(453,590)	(52.53)
20	UNIT COST ($/TON)	103.31	106.60	(3.29)	(3.09)	109.05	108.14	0.91	0.84
21	AMOUNT ($)	15,800,687	32,069,310	(16,268,623)	(50.73)	44,693,165	93,375,228	(48,682,063)	(52.14)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	918,673	710,701	207,972	29.26	918,673	710,701	207,972	29.26
24	UNIT COST ($/TON)	105.13	108.43	(3.30)	(3.04)	105.13	108.43	(3.30)	(3.04)
25	AMOUNT ($)	96,578,862	77,064,118	19,514,744	25.32	96,578,862	77,064,118	19,514,744	25.32
26	DAYS SUPPLY	44	34	10	29.41	44	34	10	29.41
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	3,100,469	2,311,744	788,725	34.12	8,941,213	6,879,787	2,061,426	29.96
29	UNIT COST ($/MMBTU)	2.67	4.91	(2.24)	(45.62)	2.92	4.93	(2.01)	(40.77)
30	AMOUNT ($)	8,274,353	11,354,506	(3,080,153)	(27.13)	26,097,201	33,913,422	(7,816,221)	(23.05)
31	*BURNED:*								
32	UNITS (MMBTU)	3,067,215	2,311,744	755,471	32.68	8,933,730	6,879,787	2,053,943	29.85
33	UNIT COST ($/MMBTU)	2.75	4.91	(2.16)	(43.99)	3.03	4.93	(1.90)	(38.54)
34	AMOUNT ($)	8,433,416	11,354,506	(2,921,090)	(25.73)	27,028,174	33,913,422	(6,885,248)	(20.30)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	1,037,061	0	1,037,061	100.00	1,037,061	0	1,037,061	100.00
37	UNIT COST ($/MMBTU)	2.82	0.00	2.82	100.00	2.82	0.00	2.82	100.00
38	AMOUNT ($)	2,926,951	0	2,926,951	100.00	2,926,951	0	2,926,951	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	0	0	0	0.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	AMOUNT ($)	0	0	0	0.00	0	0	0	0.00
43	*BURNED:*								
44	UNITS (BBL)	78	0	78	100.00	439	0	439	100.00
45	UNIT COST ($/BBL)	100.54	0.00	100.54	100.00	100.04	0.00	100.04	100.00
46	AMOUNT ($)	7,842	0	7,842	100.00	43,917	0	43,917	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,387	7,143	(756)	(10.58)	6,387	7,143	(756)	(10.58)
49	UNIT COST ($/BBL)	99.97	97.52	2.45	2.51	99.97	97.52	2.45	2.51
50	AMOUNT ($)	638,477	696,578	(58,101)	(8.34)	638,477	696,578	(58,101)	(8.34)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

	(1) SOLD TO	(2) TYPE AND SCHEDULE	CURRENT MONTH (3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) (5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(8) (5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		98,676,000	0	98,676,000	3.52	3.87	3,474,000	3,821,000
2	Various	Economy Sales	12,033,000	0	12,033,000	3.47	3.92	418,000	472,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	60,000	0
4	TOTAL ESTIMATED SALES		110,709,000	0	110,709,000	3.57	3.88	3,952,000	4,293,000
	ACTUAL								
5	Southern Company Interchange		580,872,823	0	580,872,823	2.26	2.49	13,143,165	14,452,822
6	A.E.C.	External	50,372	0	50,372	2.51	3.78	1,265	1,903
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	0	0
13	CARGILE	External	26,323	0	26,323	2.31	2.89	607	761
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	66,359	0	66,359	1.77	3.11	1,173	2,063
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	0	0	0	0.00	0.00	6	0
19	EAGLE EN	External	178,403	0	178,403	1.85	2.85	3,296	5,078
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	6,499	0	6,499	2.91	4.30	189	279
22	ENTERGY	External	0	0	0	0.00	0.00	0	0
23	FPC	External	10,595	0	10,595	1.79	3.00	190	318
24	FPL	External	601,648	0	601,648	2.32	3.45	13,974	20,744
25	JARON	External	0	0	0	0.00	0.00	1	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	51,799	0	51,799	2.57	3.81	1,332	1,972
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MORGAN	External	82,090	0	82,090	2.04	3.09	1,671	2,538
31	NCEMC	External	0	0	0	0.00	0.00	0	0
32	NCMPA1	External	0	0	0	0.00	0.00	0	0
33	NRG	External	0	0	0	0.00	0.00	0	0
34	OPC	External	8,125	0	8,125	3.79	5.12	308	416
35	ORLANDO	External	0	0	0	0.00	0.00	0	0
36	PJM	External	427,599	0	427,599	1.62	2.47	6,925	10,556
37	REMC	External	0	0	0	0.00	0.00	0	0
38	SCE&G	External	401,452	0	401,452	2.45	3.20	9,848	12,847
39	SEC	External	128,690	0	128,690	2.03	2.72	2,614	3,503
40	SEPA	External	0	0	0	0.00	0.00	0	0
41	SHELL	External	0	0	0	0.00	0.00	0	0
42	TAL	External	0	0	0	0.00	0.00	0	0
43	TEA	External	418,965	0	418,965	1.73	2.66	7,240	11,164
44	TECO	External	159,106	0	159,106	2.02	2.75	3,217	4,369
45	TENASKA	External	4,875	0	4,875	2.36	3.40	115	166
46	TVA	External	66,097	0	66,097	2.08	3.44	1,377	2,277
47	WRI	External	0	0	0	0.00	0.00	(26)	0
48	Less: Flow-Thru Energy		(2,688,997)	0	(2,688,997)	2.06	2.06	(55,308)	(55,308)
49	SEPA		1,409,408	1,409,408	0	0.00	0.00	0	0
50	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	(13,490)	(13,490)
51	Other transactions including adj.		244,063,718	139,377,167	104,686,551	0.00	0.00	0	0
52	TOTAL ACTUAL SALES		826,345,949	140,786,575	685,559,374	1.59	1.75	13,129,690	14,478,467
53	Difference in Amount		715,636,949	140,786,575	574,850,374	(1.98)	(2.13)	9,177,690	10,185,467
54	Difference in Percent		646.41	0.00	519.24	(55.46)	(54.90)	232.23	237.26

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 50

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) FUEL COST ¢/KWH	(6) (b) TOTAL COST ¢/KWH	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		214,152,000	0	214,152,000	3.57	3.91	7,648,000	8,378,000
2	Various	Economy Sales	41,948,000	0	41,948,000	3.57	3.97	1,496,000	1,667,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	207,000	0
4	TOTAL ESTIMATED SALES		256,100,000	0	256,100,000	3.65	3.92	9,351,000	10,045,000
	ACTUAL								
5	Southern Company Interchange		1,503,805,859	0	1,503,805,859	2.22	2.42	33,419,291	36,363,633
6	A.E.C.	External	559,274	0	559,274	2.45	3.23	13,680	18,056
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	30,221	0	30,221	2.36	3.53	714	1,066
13	CARGILE	External	1,241,238	0	1,241,238	2.09	2.78	25,933	34,537
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	321,394	0	321,394	1.96	2.82	6,302	9,071
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	1,756,004	0	1,756,004	2.03	2.70	35,590	47,344
19	EAGLE EN	External	294,031	0	294,031	2.07	3.03	6,078	8,916
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	6,499	0	6,499	2.91	4.30	189	279
22	ENTERGY	External	476,584	0	476,584	3.02	6.98	14,415	33,278
23	FPC	External	59,340	0	59,340	3.78	6.12	2,240	3,632
24	FPL	External	692,637	0	692,637	2.30	3.47	15,935	24,020
25	JARON	External	26,000	0	26,000	1.66	2.20	431	572
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	248,475	0	248,475	2.35	3.18	5,842	7,895
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MORGAN	External	314,706	0	314,706	1.98	2.77	6,225	8,705
31	NCEMC	External	6,500	0	6,500	1.80	2.89	117	188
32	NCMPA1	External	1,690	0	1,690	2.68	3.80	45	64
33	NRG	External	0	0	0	0.00	0.00	0	0
34	OPC	External	221,688	0	221,688	2.25	3.31	4,987	7,327
35	ORLANDO	External	0	0	0	0.00	0.00	0	0
36	PJM	External	3,177,243	0	3,177,243	1.92	2.98	61,161	94,528
37	REMC	External	0	0	0	0.00	0.00	0	0
38	SCE&G	External	1,332,131	0	1,332,131	3.10	4.65	41,328	61,936
39	SEC	External	244,383	0	244,383	2.02	2.74	4,937	6,703
40	SEPA	External	192,445	0	192,445	2.12	3.19	4,079	6,133
41	SHELL	External	0	0	0	0.00	0.00	0	0
42	TAL	External	12,350	0	12,350	2.15	3.10	265	383
43	TEA	External	2,312,409	0	2,312,409	1.98	2.85	45,866	66,003
44	TECO	External	167,620	0	167,620	2.00	2.74	3,360	4,591
45	TENASKA	External	4,875	0	4,875	2.36	3.40	115	166
46	TVA	External	522,206	0	522,206	2.13	3.28	11,115	17,138
47	WRI	External	78,000	0	78,000	1.86	2.35	1,448	1,833
48	Less: Flow-Thru Energy		(14,324,253)	0	(14,324,253)	2.18	2.18	(312,629)	(312,629)
49	SEPA		4,755,784	4,755,784	0	0.00	0.00	0	0
50	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	35,246	35,246
51	Other transactions including adj.		686,355,560	500,153,349	186,202,211	0.00	0.00	0	0
52	TOTAL ACTUAL SALES		2,194,917,203	504,909,133	1,690,008,070	1.52	1.66	33,454,805	36,516,165
53	Difference in Amount		1,938,817,203	504,909,133	1,433,908,070	(2.13)	(2.26)	24,103,805	26,471,165
54	Difference in Percent		757.05	0.00	559.90	(58.36)	(57.65)	257.77	263.53

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 50

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: MARCH 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

CURRENT MONTH

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	17
5	Ascend Performance Materials	COG 1	17,234,000	0	0	0	2.42	2.42	416,212
6	International Paper	COG 1	96,000	0	0	0	2.35	2.35	2,260
7	TOTAL		17,330,000	0	0	0	2.41	2.41	418,489

PERIOD-TO-DATE

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.38	7.38	311,923
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	17
5	Ascend Performance Materials	COG 1	51,462,000	0	0	0	2.43	2.43	1,252,114
6	International Paper	COG 1	161,000	0	0	0	2.46	2.46	3,956
7	TOTAL		55,849,000	0	0	0	2.81	2.81	1,568,010

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2012

	(1)	CURRENT MONTH (2)	(3)	(4)	PERIOD - TO - DATE (5)	(6)	(7)
	PURCHASED FROM	TOTAL KWH PURCHASED	TRANS. COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.	TOTAL KWH PURCHASED	TRANS. COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	39,043,000	3.84	1,498,000	255,496,000	3.97	10,140,000
2	Economy Energy	2,899,000	3.79	110,000	13,049,000	3.88	506,000
3	Other Purchases	0	0.00	0	3,799,000	5.37	204,000
4	TOTAL ESTIMATED PURCHASES	41,942,000	3.83	1,608,000	272,344,000	3.98	10,850,000
	ACTUAL						
5	Southern Company Interchange	83,435,558	2.70	2,248,851	188,137,680	2.51	4,728,837
6	Non-Associated Companies	12,794,869	2.53	324,321	67,100,469	3.01	2,016,972
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	568,858,000	1.87	10,634,010	1,598,462,000	2.15	34,376,881
9	Other Wheeled Energy	135,100,000	0.00	N/A	251,757,000	0.00	N/A
10	Other Transactions	112,473,611	0.02	21,587	445,858,543	0.01	55,084
11	Less: Flow-Thru Energy	(2,688,997)	2.25	(60,612)	(14,324,253)	2.41	(344,710)
12	TOTAL ACTUAL PURCHASES	909,973,041	1.45	13,168,157	2,536,991,439	1.61	40,833,064
13	Difference in Amount	868,031,041	(2.38)	11,560,157	2,264,647,439	(2.37)	29,983,064
14	Difference in Percent	2,069.60	(62.14)	718.92	831.54	(59.55)	276.34

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339							1,211,099
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ -		$ -		$ -	$ 1,211,099
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018							4,670,058
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)							(18,161)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ -		$ -		$ -	$ 4,651,897
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ -**		**$ -**		**$ -**	**$ 5,862,996**

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 55 of 209

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													1,211,099
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,211,099
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													4,670,058
2 Other Confidential Agreements	Other	Varies	Varies													(18,161)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 4,651,897
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 5,862,996

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

APRIL 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2012
CURRENT MONTH

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	25,447,963	41,849,751	(16,401,788)	(39.19)	692,367,000	889,030,000	(196,663,000)	(22.12)	3.6755	4.7073	(1.03)	(21.92)
2	Hedging Settlement Costs (A2)	3,254,010	0	3,254,010	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	8,727	0	8,727	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	28,710,700	41,849,751	(13,139,051)	(31.40)	692,367,000	889,030,000	(196,663,000)	(22.12)	4.1467	4.7073	(0.56)	(11.91)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	8,452,985	4,603,000	3,849,985	83.64	624,106,653	110,487,000	513,619,653	464.87	1.3544	4.1661	(2.81)	(67.49)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	336,968	0	336,968	100.00	15,170,000	0	15,170,000	100.00	2.2213	0.0000	2.22	0.00
12	TOTAL COST OF PURCHASED POWER	8,789,953	4,603,000	4,186,953	90.96	639,276,653	110,487,000	528,789,653	478.60	1.3750	4.1661	(2.79)	(67.00)
13	Total Available MWH (Line 5 + Line 12)	37,500,653	46,452,751	(8,952,098)	(19.27)	1,331,643,653	999,517,000	332,126,653	33.23				
14	Fuel Cost of Economy Sales (A6)	(209,837)	(423,000)	213,163	(50.39)	(9,204,053)	(11,809,000)	2,604,947	(22.06)	(2.2798)	(3.5820)	1.30	36.35
15	Gain on Economy Sales (A6)	(85,976)	(59,000)	(26,976)	45.72	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(6,150,254)	(3,306,000)	(2,844,254)	86.03	(473,029,004)	(98,422,000)	(374,607,004)	380.61	(1.3002)	(3.3590)	2.06	61.29
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(6,446,067)	(3,788,000)	(2,658,067)	70.17	(482,233,057)	(110,231,000)	(372,002,057)	337.47	(1.3367)	(3.4364)	2.10	61.10
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	31,054,586	42,664,751	(11,610,165)	(27.21)	849,410,596	889,286,000	(39,875,404)	(4.48)	3.6560	4.7976	(1.14)	(23.80)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	53,551	81,943	(28,392)	(34.65)	1,464,755	1,708,000	(243,245)	(14.24)	3.6560	4.7976	(1.14)	(23.80)
22	T & D Losses *	1,746,430	1,902,056	(155,626)	(8.18)	47,768,865	39,646,000	8,122,865	20.49	3.6560	4.7976	(1.14)	(23.80)
23	TERRITORIAL KWH SALES	31,054,585	42,664,751	(11,610,165)	(27.21)	800,176,976	847,932,000	(47,755,024)	(5.63)	3.8810	5.0316	(1.15)	(22.87)
24	Wholesale KWH Sales	982,349	1,414,251	(431,902)	(30.54)	25,311,627	28,107,000	(2,795,373)	(9.95)	3.8810	5.0317	(1.15)	(22.87)
25	Jurisdictional KWH Sales	30,072,236	41,250,500	(11,178,264)	(27.10)	774,865,349	819,825,000	(44,959,651)	(5.48)	3.8810	5.0316	(1.15)	(22.87)
26	Jurisdictional Loss Multiplier	1.0015	1.0007							1.0015	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	30,117,344	41,279,375	(11,162,031)	(27.04)	774,865,349	819,825,000	(44,959,651)	(5.48)	3.8868	5.0351	(1.15)	(22.81)
28	TRUE-UP	(1,491,621)	(1,491,621)	0	0.00	774,865,349	819,825,000	(44,959,651)	(5.48)	(0.1925)	(0.1819)	(0.01)	5.83
29	TOTAL JURISDICTIONAL FUEL COST	28,625,723	39,787,754	(11,162,031)	(28.05)	774,865,349	819,825,000	(44,959,651)	(5.48)	3.6943	4.8532	(1.16)	(23.88)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.6970	4.8567	(1.16)	(23.88)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	774,865,349	819,825,000	(44,959,651)	(5.48)	0.0069	0.0066	0.00	4.55
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.7039	4.8633	(1.16)	(23.84)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.704	4.863		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: APRIL 2012

LINE	DESCRIPTION	REFERENCE		AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$	25,447,963
2	Fuel Related Transactions			0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7		8,727
4	Hedging Settlement Costs	Schedule A-2, Line A-5		3,254,010
5	Fuel Cost of Purchased Power	Schedule A-7		0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12		8,452,985
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9		0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7		336,968
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line		(6,446,067)
10	Total Fuel and Net Power Transactions		$	31,054,586

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	98,757,781	168,592,134	(69,834,353)	(41.42)	2,764,019,000	3,708,073,000	(944,054,000)	(25.46)	3.5730	4.5466	(0.97)	(21.41)
2	Hedging Settlement Costs (A2)	12,437,306	0	12,437,306	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	22,452	0	22,452	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	111,217,539	168,592,134	(57,374,595)	(34.03)	2,764,019,000	3,708,073,000	(944,054,000)	(25.46)	4.0238	4.5486	(0.52)	(11.50)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	49,286,049	15,453,000	33,833,049	218.94	3,161,098,092	382,831,000	2,778,267,092	725.72	1.5591	4.0365	(2.48)	(61.37)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	1,904,978	0	1,904,978	100.00	71,019,000	0	71,019,000	100.00	2.6823	0.0000	2.68	0.00
12	TOTAL COST OF PURCHASED POWER	51,191,027	15,453,000	35,738,027	231.27	3,232,117,092	382,831,000	2,849,286,092	744.27	1.5838	4.0365	(2.45)	(60.76)
13	Total Available MWH (Line 5 + Line 12)	162,408,566	184,045,134	(21,636,568)	(11.76)	5,996,136,092	4,090,904,000	1,905,232,092	46.57				
14	Fuel Cost of Economy Sales (A6)	(522,734)	(1,919,000)	1,396,266	(72.76)	(23,528,306)	(53,757,000)	30,228,694	(56.23)	(2.2217)	(3.5698)	1.35	37.76
15	Gain on Economy Sales (A6)	(121,222)	(266,000)	144,778	(54.43)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(39,256,916)	(10,954,000)	(28,302,916)	258.38	(2,653,621,954)	(312,574,000)	(2,341,047,954)	748.96	(1.4794)	(3.5045)	2.03	57.79
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(39,900,872)	(13,139,000)	(26,761,872)	203.68	(2,677,150,260)	(366,331,000)	(2,310,819,260)	630.80	(1.4904)	(3.5866)	2.10	58.45
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	122,507,694	170,906,134	(48,398,440)	(28.32)	3,318,985,832	3,724,573,000	(405,587,168)	(10.89)	3.6911	4.5886	(0.90)	(19.56)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	229,518	336,253	(106,735)	(31.74)	6,218,134	7,328,000	(1,109,866)	(15.15)	3.6911	4.5886	(0.90)	(19.56)
22	T & D Losses *	6,872,340	8,044,183	(1,171,843)	(14.57)	186,186,763	175,308,000	10,878,763	6.21	3.6911	4.5886	(0.90)	(19.56)
23	TERRITORIAL KWH SALES	122,507,693	170,906,134	(48,398,441)	(28.32)	3,126,580,935	3,541,937,000	(415,356,065)	(11.73)	3.9183	4.8252	(0.91)	(18.80)
24	Wholesale KWH Sales	4,108,477	5,841,838	(1,733,361)	(29.67)	104,525,753	121,088,000	(16,562,247)	(13.68)	3.9306	4.8245	(0.89)	(18.53)
25	Jurisdictional KWH Sales	118,399,216	165,064,296	(46,665,080)	(28.27)	3,022,055,182	3,420,849,000	(398,793,818)	(11.66)	3.9178	4.8252	(0.91)	(18.81)
26	Jurisdictional Loss Multiplier***	1.0015	1.0007							1.0015	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	118,506,153	165,179,841	(46,673,688)	(28.26)	3,022,055,182	3,420,849,000	(398,793,818)	(11.66)	3.9214	4.8286	(0.91)	(18.79)
28	TRUE-UP	(974,712)	(974,712)	0	0.00	3,022,055,182	3,420,849,000	(398,793,818)	(11.66)	(0.0323)	(0.0285)	(0.00)	13.33
29	TOTAL JURISDICTIONAL FUEL COST	117,531,441	164,205,129	(46,673,688)	(28.42)	3,022,055,182	3,420,849,000	(398,793,818)	(11.66)	3.8891	4.8001	(0.91)	(18.98)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.8919	4.8036	(0.91)	(18.98)
32	GPIF Reward / (Penalty)	215,172	215,172	0	0.00	3,022,055,182	3,420,849,000	(398,793,818)	(11.66)	0.0071	0.0063	0.00	12.70
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.8990	4.8099	(0.91)	(18.94)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.899	4.810		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	25,208,639.54	41,715,558	(16,506,918.76)	(39.57)	97,847,941.25	168,050,903	(70,202,962.10)	(41.77)
1a	Other Generation	239,324.68	134,193	105,131.68	78.34	909,841.03	541,231	368,610.03	68.11
2	Fuel Cost of Power Sold	(6,446,067.37)	(3,788,000)	(2,658,067.37)	(70.17)	(39,900,871.69)	(13,139,000)	(26,761,871.69)	(203.68)
3	Fuel Cost - Purchased Power	8,452,983.52	4,603,000	3,849,983.52	83.64	49,286,047.12	15,453,000	33,833,047.12	218.94
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	336,968.19	0	336,968.19	100.00	1,904,978.26	0	1,904,978.26	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	3,254,010.00	0	3,254,010.00	100.00	12,437,306.00	0	12,437,306.00	100.00
6	Total Fuel & Net Power Transactions	31,045,858.56	42,664,751	(11,618,892.74)	(27.23)	122,485,241.97	170,906,134	(48,420,892.38)	(28.33)
7	AdjustmentsTo Fuel Cost*	8,726.78	0	8,726.78	100.00	22,451.79	0	22,451.79	100.00
8	Adj. Total Fuel & Net Power Transactions	31,054,585.34	42,664,751	(11,610,165.66)	(27.21)	122,507,693.76	170,906,134	(48,398,440.59)	(28.32)
B.	*KWH Sales*								
1	Jurisdictional Sales	774,865,349	819,825,000	(44,959,651)	(5.48)	3,022,055,182	3,420,849,000	(398,793,818)	(11.66)
2	Non-Jurisdictional Sales	25,311,627	28,107,000	(2,795,373)	(9.95)	104,525,753	121,088,000	(16,562,247)	(13.68)
3	Total Territorial Sales	800,176,976	847,932,000	(47,755,024)	(5.63)	3,126,580,935	3,541,937,000	(415,356,065)	(11.73)
4	Juris. Sales as % of Total Terr. Sales	96.8367	96.6852	0.1515	0.16	96.6569	96.5813	0.0756	0.08

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	35,752,540.29	37,847,221	(2,094,680.84)	(5.53)	143,211,554.83	163,640,174	(20,428,619.06)	(12.48)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	1,491,620.90	1,491,621	0.00	0.00	974,710.96	974,711	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(215,015.52)	(215,016)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	37,190,407.31	39,285,088	(2,094,680.69)	(5.33)	143,971,250.27	164,399,869	(20,428,618.73)	(12.43)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	31,054,585.34	42,664,751	(11,610,165.66)	(27.21)	122,507,693.76	170,906,134	(48,398,440.24)	(28.32)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.8367	96.6852	0.1515	0.16	96.6569	96.5813	0.0756	0.08
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	30,117,344.00	41,279,375	(11,162,031.00)	(27.04)	118,506,152.52	165,179,841	(46,673,688.48)	(28.26)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	7,073,063.31	(1,994,287)	9,067,350.31	454.67	25,465,097.75	(779,972)	26,245,069.75	3,364.87
8	Interest Provision for the Month	2,783.65	(1,062)	3,845.65	362.11	6,777.08	(3,327)	10,104.08	303.70
9	Beginning True-Up & Interest Provision	28,841,631.50	(10,322,225)	39,163,856.50	379.41	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(1,491,620.90)	(1,491,621)	0.00	0.00	(974,710.96)	(974,711)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	34,425,857.56	(13,809,195)	48,235,052.56	349.30	34,425,857.56	(13,809,195)	48,235,052.56	349.30
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	34,425,857.56	(13,809,195)	48,235,052.56	349.30	34,425,857.56	(13,809,195)	48,235,052.56	349.30

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

		CURRENT MONTH			
		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	28,841,631.50	(10,322,225)	39,163,856.50	(379.41)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	34,423,073.91	(13,808,133)	48,231,206.91	(349.30)
3	Total of Beginning & Ending True-Up Amts.	63,264,705.41	(24,130,358)	87,395,063.41	(362.18)
4	Average True-Up Amount	31,632,352.71	(12,065,179)	43,697,531.71	(362.18)
5	Interest Rate 1st Day of Reporting Business Month	0.09	0.09	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.12	0.12	0.0000	
7	Total (D5+D6)	0.21	0.21	0.0000	
8	Annual Average Interest Rate	0.11	0.11	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0088	0.0088	0.0000	
10	Interest Provision (D4*D9)	2,783.65	(1,062)	3,845.65	(362.11)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0007		

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	112,224	55,329	56,895	102.83	415,798	220,896	194,902	88.23
2	COAL	18,075,447	32,959,062	(14,883,615)	(45.16)	63,154,954	126,334,291	(63,179,337)	(50.01)
3	GAS	5,866,629	8,779,174	(2,912,545)	(33.18)	33,541,380	41,810,180	(8,268,800)	(19.78)
4	GAS (B.L.)	1,282,090	0	1,282,090	100.00	1,306,030	-	1,306,030	100.00
5	LANDFILL GAS	60,566	56,186	4,380	7.80	244,695	226,768	17,927	7.91
6	OIL - C.T.	51,007	0	51,007	100.00	94,924	0	94,924	100.00
7	TOTAL ($)	25,447,963	41,849,751	(16,401,788)	(39.19)	98,757,781	168,592,135	(69,834,354)	(41.42)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	398,579	661,221	(262,642)	(39.72)	1,250,346	2,492,690	(1,242,344)	(49.84)
10	GAS	291,528	225,643	65,885	29.20	1,504,733	1,206,641	298,092	24.70
11	LANDFILL GAS	2,099	2,166	(67)	(3.09)	8,631	8,742	(111)	(1.27)
12	OIL - C.T.	161	0	161	100.00	309	0	309	100.00
13	TOTAL (MWH)	692,367	889,030	(196,663)	(22.12)	2,764,019	3,708,073	(944,054)	(25.46)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	832	408	424	103.95	3,266	1,632	1,634	100.15
15	COAL (TONS)	167,665	312,213	(144,548)	(46.30)	577,504	1,175,642	(598,138)	(50.88)
16	GAS (MCF) (1)	2,245,984	1,449,472	796,512	54.95	11,054,463	8,128,878	2,925,585	35.99
17	OIL - C.T. (BBL)	491	0	491	100.00	930	0	930	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	4,862,802	7,182,869	(2,320,067)	(32.30)	14,458,689	27,088,834	(12,630,145)	(46.62)
19	GAS - Generation (1)	1,712,992	1,492,956	220,036	14.74	10,638,454	8,372,743	2,265,711	27.06
20	OIL - C.T.	2,853	0	2,853	100.00	5,406	0	5,406	100.00
21	TOTAL (MMBTU)	6,578,647	8,675,825	(2,097,178)	(24.17)	25,102,549	35,461,577	(10,359,028)	(29.21)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	57.57	74.38	(16.81)	(22.60)	45.24	67.22	(21.98)	(32.70)
24	GAS	42.11	25.38	16.73	65.92	54.44	32.54	21.90	67.30
25	LANDFILL GAS	0.30	0.24	0.06	25.00	0.31	0.24	0.07	29.17
26	OIL - C.T.	0.02	0.00	0.02	100.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	134.88	135.65	(0.77)	(0.57)	127.31	135.39	(8.08)	(5.97)
29	COAL ($/TON)	107.81	105.57	2.24	2.12	109.36	107.46	1.90	1.77
30	GAS ($/MCF) (1)	3.08	5.96	(2.88)	(48.32)	3.07	5.08	(2.01)	(39.57)
31	OIL - C.T. ($/BBL)	103.88	0.00	103.88	100.00	102.07	0.00	102.07	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.00	4.60	(0.60)	(13.04)	4.49	4.67	(0.18)	(3.85)
33	GAS - Generation (1)	3.29	5.79	(2.50)	(43.18)	3.07	4.93	(1.86)	(37.73)
34	OIL - C.T.	17.88	0.00	17.88	100.00	17.56	0.00	17.56	100.00
35	TOTAL ($/MMBTU)	3.82	4.80	(0.98)	(20.42)	3.89	4.73	(0.84)	(17.76)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	12,200	10,863	1,337	12.31	11,564	10,867	697	6.41
37	GAS - Generation (1)	6,039	6,699	(660)	(9.85)	7,206	7,004	202	2.88
38	OIL - C.T.	17,720	0	17,720	100.00	17,495	0	17,495	100.00
39	TOTAL (BTU/KWH)	9,641	9,813	(172)	(1.75)	9,206	9,615	(409)	(4.25)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.88	4.99	(0.11)	(2.20)	5.19	5.08	0.11	2.17
41	GAS	2.01	3.89	(1.88)	(48.33)	2.23	3.47	(1.24)	(35.73)
42	LANDFILL GAS	2.89	2.59	0.30	11.58	2.84	2.59	0.25	9.65
43	OIL - C.T.	31.68	0.00	31.68	100.00	30.72	0.00	30.72	100.00
44	TOTAL (¢/KWH)	3.68	4.71	(1.03)	(21.87)	3.57	4.55	(0.98)	(21.54)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	5,197	9.6	100.0	49.6	10,979	Coal	2,455	11,621	57,056	258,474	4.97	105.28
2				0					Gas-G	0	1,015	0	0	0.00	0.00
3									Gas-S	0	1,015	0	0		0.00
4									Oil-S	8	137,918	47	915		114.38
5	Crist 5		75	25,662	50.9	97.9	62.8	12,808	Coal	14,088	11,665	328,684	1,483,390	5.78	105.29
6				1,834					Gas-G	0	1,015	0	0	0.00	0.00
7									Gas-S	0	1,015	0	0		0.00
8									Oil-S	50	137,918	289	5,561		111.22
9	Crist 6		291	21,001	10.0	21.8	46.0	7,044	Coal	6,281	11,776	147,921	661,292	3.15	105.28
10				0					Gas-G	0	1,015	0	0	0.00	0.00
11									Gas-S	554,975	1,015	563,300	1,282,090		2.31
12									Oil-S	0	137,918	0	0		0.00
13	Crist 7		465	129,812	51.8	96.0	55.1	11,730	Coal	65,158	11,685	1,522,742	6,860,566	5.29	105.29
14				43,756					Gas-G	0	1,015	0	0	0.00	0.00
15									Gas-S	0	1,015	0	0		0.00
16									Oil-S	76	137,918	442	8,513		112.01
17	Scholz 1		46	(142)	(0.4)	51.8	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	138,460	0	0		0.00
19	Scholz 2		46	(179)	(0.5)	61.8	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	138,460	0	0		0.00
21	Smith 1		162	41,846	35.9	77.3	46.0	10,746	Coal	20,049	11,215	449,693	2,514,651	6.01	125.43
22									Oil-S	415	138,066	2,407	58,219		140.29
23	Smith 2		195	38,887	27.7	100.0	40.7	10,622	Coal	18,153	11,377	413,051	2,276,861	5.86	125.43
24									Oil-S	241	138,066	1,396	33,752		140.05
25	Smith 3		531	238,065	62.3	73.9	92.2	7,195	Gas-G	1,691,009	1,013	1,712,991	5,627,304	2.36	3.33
26	Smith A	(2)	40	161	0.6	95.6	61.0	17,720	Oil	491	138,370	2,853	51,007	31.68	103.88
27	Other Generation			7,873									239,325	3.04	0.00
28	Perdido			2,099					Landfill Gas				60,566	2.89	0.00
29	Daniel 1	(1)	255	(1,245)	(0.7)	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	140,406	0	0		0.00
31	Daniel 2	(1)	255	137,740	75.0	99.8	75.1	9,986	Coal	63,381	10,851	1,375,531	5,768,952	4.19	91.02
32									Oil-S	41	140,406	244	5,264		128.39
33	Total		2,436	692,367	39.5	70.4	54.8	9,641				6,578,647	27,196,702	3.93	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	145,104	
(21,899)	Daniel Coal Adjustment	(1,889,785)	
	Recoverable Fuel	25,447,962	3.68

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 65 of 209

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

		CURRENT MONTH		DIFFERENCE		PERIOD-TO-DATE		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	710	1,226	(516)	(42.09)	2,309	4,904	(2,595)	(52.92)
3	UNIT COST ($/BBL)	140.50	135.18	5.32	3.94	135.73	135.18	0.55	0.41
4	AMOUNT ($)	99,754	165,728	(65,974)	(39.81)	313,409	662,912	(349,503)	(52.72)
5	*BURNED:*								
6	UNITS (BBL)	892	408	484	118.63	3,419	1,632	1,787	109.50
7	UNIT COST ($/BBL)	135.30	135.61	(0.31)	(0.23)	127.67	135.35	(7.68)	(5.67)
8	AMOUNT ($)	120,689	55,329	65,360	118.13	436,505	220,896	215,609	97.61
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	4,277	18,578	(14,301)	(76.98)	4,277	18,578	(14,301)	(76.98)
11	UNIT COST ($/BBL)	120.66	58.61	62.05	105.87	120.66	58.61	62.05	105.87
12	AMOUNT ($)	516,061	1,088,808	(572,747)	(52.60)	516,061	1,088,808	(572,747)	(52.60)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	208,119	236,581	(28,462)	(12.03)	635,282	902,972	(267,690)	(29.65)
16	UNIT COST ($/TON)	103.57	108.94	(5.37)	(4.93)	107.99	111.98	(3.99)	(3.56)
17	AMOUNT ($)	21,555,892	25,773,141	(4,217,249)	(16.36)	68,604,078	101,111,556	(32,507,478)	(32.15)
18	*BURNED:*								
19	UNITS (TONS)	167,665	312,213	(144,548)	(46.30)	577,504	1,175,642	(598,138)	(50.88)
20	UNIT COST ($/TON)	106.97	105.57	1.40	1.33	108.45	107.46	0.99	0.92
21	AMOUNT ($)	17,934,402	32,959,062	(15,024,660)	(45.59)	62,627,567	126,334,290	(63,706,723)	(50.43)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	959,127	635,069	324,058	51.03	959,127	635,069	324,058	51.03
24	UNIT COST ($/TON)	104.47	110.03	(5.56)	(5.05)	104.47	110.03	(5.56)	(5.05)
25	AMOUNT ($)	100,200,352	69,878,197	30,322,155	43.39	100,200,352	69,878,197	30,322,155	43.39
26	DAYS SUPPLY	46	31	15	48.39	46	31	15	48.39
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,276,292	1,492,956	783,336	52.47	11,217,505	8,372,743	2,844,762	33.98
29	UNIT COST ($/MMBTU)	3.25	5.79	(2.54)	(43.87)	2.99	5.08	(2.09)	(41.14)
30	AMOUNT ($)	7,389,264	8,644,981	(1,255,717)	(14.53)	33,486,485	42,558,403	(9,071,938)	(21.32)
31	*BURNED:*								
32	UNITS (MMBTU)	2,276,292	1,492,956	783,336	52.47	11,210,022	8,372,743	2,837,279	33.89
33	UNIT COST ($/MMBTU)	3.04	5.79	(2.75)	(47.50)	3.03	5.08	(2.05)	(40.35)
34	AMOUNT ($)	6,909,394	8,644,981	(1,735,587)	(20.08)	33,937,568	42,558,403	(8,620,835)	(20.26)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	1,037,061	0	1,037,061	100.00	1,037,061	0	1,037,061	100.00
37	UNIT COST ($/MMBTU)	3.29	0.00	3.29	100.00	3.29	0.00	3.29	100.00
38	AMOUNT ($)	3,406,821	0	3,406,821	100.00	3,406,821	0	3,406,821	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	710	0	710	100.00	710	0	710	100.00
41	UNIT COST ($/BBL)	139.29	0.00	139.29	100.00	139.29	0.00	139.00	100.00
42	AMOUNT ($)	98,899	0	98,899	100.00	98,899	0	98,899	100.00
43	*BURNED:*								
44	UNITS (BBL)	491	0	491	100.00	930	0	930	100.00
45	UNIT COST ($/BBL)	103.88	0.00	103.88	100.00	102.07	0.00	102.07	100.00
46	AMOUNT ($)	51,007	0	51,007	100.00	94,924	0	94,924	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,606	7,143	(537)	(7.52)	6,606	7,143	(537)	(7.52)
49	UNIT COST ($/BBL)	103.90	97.52	6.38	6.54	103.90	97.52	6.38	6.54
50	AMOUNT ($)	686,369	696,578	(10,209)	(1.47)	686,369	696,578	(10,209)	(1.47)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		98,422,000	0	98,422,000	3.36	3.69	3,306,000	3,631,000
2	Various	Economy Sales	11,809,000	0	11,809,000	3.58	4.00	423,000	472,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	59,000	0
4	TOTAL ESTIMATED SALES		110,231,000	0	110,231,000	3.44	3.72	3,788,000	4,103,000
	ACTUAL								
5	Southern Company Interchange		285,519,290	0	285,519,290	2.23	2.43	6,357,978	6,945,665
6	A.E.C.	External	6,500	0	6,500	3.29	4.40	214	286
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	106,864	0	106,864	3.19	3.57	3,477	3,890
13	CARGILE	External	97,166	0	97,166	3.06	4.14	2,970	4,024
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	53,814	0	53,814	2.36	4.15	1,271	2,231
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	887,211	0	887,211	1.75	2.60	15,528	23,024
19	EAGLE EN	External	52,774	0	52,774	2.91	5.01	1,536	2,647
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	24,306	0	24,306	1.36	3.51	330	852
22	ENTERGY	External	3,064,728	0	3,064,728	2.62	5.71	80,333	175,144
23	FPC	External	0	0	0	0.00	0.00	0	0
24	FPL	External	1,575,951	0	1,575,951	2.42	3.80	38,087	59,831
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	22,748	0	22,748	3.01	4.27	684	971
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	166,712	0	166,712	1.95	3.13	3,255	5,218
32	NCEMC	External	6,174	0	6,174	2.00	2.70	123	167
33	NCMPA1	External	277,281	0	277,281	2.46	2.93	6,834	8,121
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	37,371	0	37,371	1.59	2.76	595	1,030
36	ORLANDO	External	650	0	650	2.75	4.80	18	31
37	PJM	External	1,542,644	0	1,542,644	1.66	2.66	25,682	41,032
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	395,173	0	395,173	2.99	3.90	11,807	15,403
40	SEC	External	80,979	0	80,979	1.97	2.79	1,597	2,256
41	SEPA	External	54,269	0	54,269	2.96	3.80	1,607	2,062
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	0	0	0	0.00	0.00	0	0
44	TEA	External	502,290	0	502,290	1.77	2.69	8,899	13,508
45	TECO	External	77,992	0	77,992	3.08	5.95	2,400	4,640
46	TENASKA	External	6,499	0	6,499	2.54	3.80	165	247
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	32,496	0	32,496	2.00	3.30	651	1,072
49	WRI	External	0	0	0	0.00	0.00	0	0
50	Less: Flow-Thru Energy		(9,118,719)	0	(9,118,719)	2.28	2.28	(207,724)	(207,724)
51	SEPA		956,384	956,384	0	0.00	0.00	0	0
52	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	85,976	85,976
53	Other transactions including adj.		195,672,049	162,602,340	33,069,709	0.00	0.00	0	0
54	TOTAL ACTUAL SALES		482,233,057	163,558,724	318,674,333	1.34	1.47	6,446,067	7,108,051
55	Difference in Amount		372,002,057	163,558,724	208,443,333	(2.10)	(2.25)	2,658,067	3,005,051
56	Difference in Percent		337.47	0.00	189.10	(61.05)	(60.48)	70.17	73.24

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 52

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			PERIOD TO DATE						
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		312,574,000	0	312,574,000	3.50	3.84	10,954,000	12,009,000
2	Various	Economy Sales	53,757,000	0	53,757,000	3.57	3.98	1,919,000	2,139,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	266,000	0
4	TOTAL ESTIMATED SALES		366,331,000	0	366,331,000	3.59	3.86	13,139,000	14,148,000
	ACTUAL								
5	Southern Company Interchange		1,789,325,149	0	1,789,325,149	2.22	2.42	39,777,269	43,309,298
6	A.E.C.	External	565,774	0	565,774	2.46	3.24	13,893	18,342
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	139,085	0	139,085	3.01	3.56	4,191	4,955
13	CARGILE	External	1,338,404	0	1,338,404	2.16	2.88	28,902	38,561
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	375,208	0	375,208	2.02	3.01	7,574	11,302
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	2,643,215	0	2,643,215	1.93	2.66	51,118	70,368
19	EAGLE EN	External	346,805	0	346,805	2.20	3.33	7,614	11,562
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	30,805	0	30,805	1.68	3.67	519	1,132
22	ENTERGY	External	3,541,312	0	3,541,312	2.68	5.89	94,748	208,422
23	FPC	External	59,340	0	59,340	3.78	6.12	2,240	3,632
24	FPL	External	2,268,588	0	2,268,588	2.38	3.70	54,021	83,851
25	JARON	External	26,000	0	26,000	1.66	2.20	431	572
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	271,223	0	271,223	2.41	3.27	6,526	8,868
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	481,418	0	481,418	1.97	2.89	9,480	13,923
32	NCEMC	External	12,674	0	12,674	1.90	2.80	241	355
33	NCMPA1	External	278,971	0	278,971	2.47	2.93	6,879	8,185
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	259,059	0	259,059	2.15	3.23	5,582	8,357
36	ORLANDO	External	650	0	650	2.75	4.80	18	31
37	PJM	External	4,719,887	0	4,719,887	1.84	2.87	86,843	135,560
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	1,727,304	0	1,727,304	3.08	4.48	53,135	77,339
40	SEC	External	325,362	0	325,362	2.01	2.75	6,533	8,959
41	SEPA	External	246,714	0	246,714	2.30	3.32	5,686	8,195
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	12,350	0	12,350	2.15	3.10	265	383
44	TEA	External	2,814,699	0	2,814,699	1.95	2.82	54,765	79,511
45	TECO	External	245,612	0	245,612	2.35	3.76	5,761	9,231
46	TENASKA	External	11,374	0	11,374	2.48	3.63	280	413
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	554,702	0	554,702	2.12	3.28	11,765	18,211
49	WRI	External	78,000	0	78,000	1.86	2.35	1,448	1,833
50	Less: Flow-Thru Energy		(23,442,972)	0	(23,442,972)	2.22	2.22	(520,353)	(520,353)
51	SEPA		5,712,168	5,712,168	0	0.00	0.00	0	0
52	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	121,222	121,222
53	Other transactions including adj.		882,027,609	662,755,689	219,271,920	0.00	0.00	0	0
54	TOTAL ACTUAL SALES		2,677,150,260	668,467,857	2,008,682,403	1.49	1.63	39,900,872	43,624,216
55	Difference in Amount		2,310,819,260	668,467,857	1,642,351,403	(2.10)	(2.23)	26,761,872	29,476,216
56	Difference in Percent		630.80	0.00	448.32	(58.50)	(57.77)	203.68	208.34

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 52

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: APRIL 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

CURRENT MONTH

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	15,059,000	0	0	0	2.22	2.22	334,392
6	International Paper	COG 1	111,000	0	0	0	2.32	2.32	2,576
7	TOTAL		15,170,000	0	0	0	2.22	2.22	336,968

PERIOD-TO-DATE

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.38	7.38	311,923
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	17
5	Ascend Performance Materials	COG 1	66,521,000	0	0	0	2.38	2.38	1,586,506
6	International Paper	COG 1	272,000	0	0	0	2.40	2.40	6,532
7	TOTAL		71,019,000	0	0	0	2.68	2.68	1,904,978

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	105,795,000	4.18	4,418,000	361,291,000	4.03	14,558,000
2	Economy Energy	4,692,000	3.94	185,000	17,741,000	3.89	691,000
3	Other Purchases	0	0.00	0	3,799,000	5.37	204,000
4	TOTAL ESTIMATED PURCHASES	110,487,000	4.17	4,603,000	382,831,000	4.04	15,453,000
	ACTUAL						
5	Southern Company Interchange	98,135,109	2.24	2,194,347	286,272,789	2.42	6,923,184
6	Non-Associated Companies	7,587,928	2.45	185,787	74,688,397	2.95	2,202,759
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	328,772,000	1.91	6,274,313	1,927,234,000	2.11	40,651,194
9	Other Wheeled Energy	64,481,000	0.00	N/A	316,238,000	0.00	N/A
10	Other Transactions	134,249,335	0.02	32,597	580,107,878	0.02	87,681
11	Less: Flow-Thru Energy	(9,118,719)	2.57	(234,059)	(23,442,972)	2.47	(578,769)
12	TOTAL ACTUAL PURCHASES	624,106,653	1.35	8,452,985	3,161,098,092	1.56	49,286,049
13	Difference in Amount	513,619,653	(2.82)	3,849,985	2,778,267,092	(2.48)	33,833,049
14	Difference in Percent	464.87	(67.63)	83.64	725.72	(61.39)	218.94

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862					1,221,961
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ -		$ -	$ 1,221,961
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131					6,147,189
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)					(21,880)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ -		$ -	$ 6,125,309
TOTAL					$ 2,379,394		$ 1,733,195		$ 1,750,407		$ 1,484,274		$ -		$ -	$ 7,347,270

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													1,221,961
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,221,961
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													6,147,189
2 Other Confidential Agreements	Other	Varies	Varies													(21,880)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 6,125,309
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 7,347,270

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

MAY 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	33,252,878	50,701,008	(17,448,130)	(34.41)	816,340,000	1,059,569,000	(243,229,000)	(22.96)	4.0734	4.7851	(0.71)	(14.87)
2	Hedging Settlement Costs (A2)	3,284,575	0	3,284,575	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	51,503	0	51,503	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	36,588,956	50,701,008	(14,112,052)	(27.83)	816,340,000	1,059,569,000	(243,229,000)	(22.96)	4.4821	4.7851	(0.30)	(6.33)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,601,087	4,944,000	8,657,087	175.10	907,604,606	128,131,000	779,473,606	608.34	1.4986	3.8586	(2.36)	(61.16)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	422,654	0	422,654	100.00	15,921,000	0	15,921,000	100.00	2.6547	0.0000	2.65	0.00
12	TOTAL COST OF PURCHASED POWER	14,023,741	4,944,000	9,079,741	183.65	923,525,606	128,131,000	795,394,606	620.77	1.5185	3.8586	(2.34)	(60.65)
13	Total Available MWH (Line 5 + Line 12)	50,612,697	55,645,008	(5,032,311)	(9.04)	1,739,865,606	1,187,700,000	552,165,606	46.49				
14	Fuel Cost of Economy Sales (A6)	(296,464)	(489,000)	192,536	(39.37)	(10,109,045)	(12,922,000)	2,812,955	(21.77)	(2.9327)	(3.7842)	0.85	22.50
15	Gain on Economy Sales (A6)	(158,458)	(65,000)	(93,458)	143.78	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,464,136)	(1,907,000)	(6,557,136)	343.85	(637,207,945)	(45,332,000)	(591,875,945)	1,305.65	(1.3283)	(4.2067)	2.88	68.42
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,919,058)	(2,461,000)	(6,458,058)	262.42	(647,316,990)	(58,254,000)	(589,062,990)	1,011.20	(1.3779)	(4.2246)	2.85	67.38
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	41,693,639	53,184,008	(11,490,369)	(21.60)	1,092,548,616	1,129,446,000	(36,897,384)	(3.27)	3.8162	4.7089	(0.89)	(18.96)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	66,444	91,117	(24,673)	(27.08)	1,741,114	1,935,000	(193,886)	(10.02)	3.8162	4.7089	(0.89)	(18.96)
22	T & D Losses *	2,729,642	3,023,114	(293,472)	(9.71)	71,527,759	64,200,000	7,327,759	11.41	3.8162	4.7089	(0.89)	(18.96)
23	TERRITORIAL KWH SALES	41,693,639	53,184,008	(11,490,369)	(21.60)	1,019,279,743	1,063,311,000	(44,031,257)	(4.14)	4.0905	5.0017	(0.91)	(18.22)
24	Wholesale KWH Sales	1,142,989	1,696,304	(553,315)	(32.62)	27,942,808	33,914,000	(5,971,192)	(17.61)	4.0905	5.0018	(0.91)	(18.22)
25	Jurisdictional KWH Sales	40,550,650	51,487,704	(10,937,054)	(21.24)	991,336,935	1,029,397,000	(38,060,065)	(3.70)	4.0905	5.0017	(0.91)	(18.22)
26	Jurisdictional Loss Multiplier	1.0015	1.0007							1.0015	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	40,611,476	51,523,745	(10,912,269)	(21.18)	991,336,935	1,029,397,000	(38,060,065)	(3.70)	4.0966	5.0052	(0.91)	(18.15)
28	TRUE-UP	(1,491,621)	(1,491,621)	0	0.00	991,336,935	1,029,397,000	(38,060,065)	(3.70)	(0.1505)	(0.1449)	(0.01)	3.86
29	TOTAL JURISDICTIONAL FUEL COST	39,119,855	50,032,124	(10,912,269)	(21.81)	991,336,935	1,029,397,000	(38,060,065)	(3.70)	3.9461	4.8603	(0.91)	(18.81)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9489	4.8638	(0.91)	(18.81)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	991,336,935	1,029,397,000	(38,060,065)	(3.70)	0.0054	0.0052	0.00	3.85
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9543	4.8690	(0.91)	(18.79)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.954	4.869		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: MAY 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 33,252,878
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	51,503
4	Hedging Settlement Costs	Schedule A-2, Line A-5	3,284,575
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	13,601,087
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	422,654
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,919,058)
10	Total Fuel and Net Power Transactions		$ 41,693,639

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2012
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	132,010,660	219,293,142	(87,282,482)	(39.80)	3,580,359,000	4,767,642,000	(1,187,283,000)	(24.90)	3.6871	4.5996	(0.91)	(19.84)
2	Hedging Settlement Costs (A2)	15,721,881	0	15,721,881	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	73,955	0	73,955	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	147,806,496	219,293,142	(71,486,646)	(32.60)	3,580,359,000	4,767,642,000	(1,187,283,000)	(24.90)	4.1283	4.5996	(0.47)	(10.25)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	62,887,135	20,397,000	42,490,135	208.32	4,068,702,698	510,962,000	3,557,740,698	696.28	1.5456	3.9919	(2.45)	(61.28)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	2,327,632	0	2,327,632	100.00	86,940,000	0	86,940,000	100.00	2.6773	0.0000	2.68	0.00
12	TOTAL COST OF PURCHASED POWER	65,214,767	20,397,000	44,817,767	219.73	4,155,642,698	510,962,000	3,644,680,698	713.30	1.5693	3.9919	(2.42)	(60.69)
13	Total Available MWH (Line 5 + Line 12)	213,021,263	239,690,142	(26,668,879)	(11.13)	7,736,001,698	5,278,604,000	2,457,397,698	46.55				
14	Fuel Cost of Economy Sales (A6)	(819,198)	(2,408,000)	1,588,802	(65.98)	(33,637,351)	(66,679,000)	33,041,649	(49.55)	(2.4354)	(3.6113)	1.18	32.56
15	Gain on Economy Sales (A6)	(279,680)	(331,000)	51,320	(15.50)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(47,721,052)	(12,861,000)	(34,860,052)	271.05	(3,290,829,899)	(357,906,000)	(2,932,923,899)	819.47	(1.4501)	(3.5934)	2.14	59.65
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(48,819,930)	(15,600,000)	(33,219,930)	212.95	(3,324,467,250)	(424,585,000)	(2,899,882,250)	682.99	(1.4685)	(3.6742)	2.21	60.03
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	164,201,333	224,090,142	(59,888,809)	(26.73)	4,411,534,448	4,854,019,000	(442,484,552)	(9.12)	3.7221	4.6166	(0.89)	(19.38)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	296,251	427,636	(131,385)	(30.72)	7,959,248	9,263,000	(1,303,752)	(14.07)	3.7221	4.6166	(0.89)	(19.38)
22	T & D Losses *	9,592,392	11,057,126	(1,464,734)	(13.25)	257,714,522	239,508,000	18,206,522	7.60	3.7221	4.6166	(0.89)	(19.38)
23	TERRITORIAL KWH SALES	164,201,332	224,090,142	(59,888,810)	(26.73)	4,145,860,678	4,605,248,000	(459,387,322)	(9.98)	3.9606	4.8660	(0.91)	(18.61)
24	Wholesale KWH Sales	5,251,466	7,538,142	(2,286,676)	(30.33)	132,468,561	155,002,000	(22,533,439)	(14.54)	3.9643	4.8633	(0.90)	(18.49)
25	Jurisdictional KWH Sales	158,949,866	216,552,000	(57,602,134)	(26.60)	4,013,392,117	4,450,246,000	(436,853,883)	(9.82)	3.9605	4.8661	(0.91)	(18.61)
26	Jurisdictional Loss Multiplier***	1.0015	1.0007							1.0015	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	159,117,629	216,703,586	(57,585,957)	(26.57)	4,013,392,117	4,450,246,000	(436,853,883)	(9.82)	3.9647	4.8695	(0.90)	(18.58)
28	TRUE-UP	(2,466,333)	(2,466,333)	0	0.00	4,013,392,117	4,450,246,000	(436,853,883)	(9.82)	(0.0615)	(0.0554)	(0.01)	11.01
29	TOTAL JURISDICTIONAL FUEL COST	156,651,296	214,237,253	(57,585,957)	(26.88)	4,013,392,117	4,450,246,000	(436,853,883)	(9.82)	3.9032	4.8141	(0.91)	(18.92)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9060	4.8176	(0.91)	(18.92)
32	GPIF Reward / (Penalty)	268,965	268,965	0	0.00	4,013,392,117	4,450,246,000	(436,853,883)	(9.82)	0.0067	0.0060	0.00	11.67
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9127	4.8236	(0.91)	(18.88)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.913	4.824		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	32,960,574.76	50,423,993	(17,463,418.29)	(34.63)	130,808,516.01	218,474,896	(87,666,380.39)	(40.13)
1a	Other Generation	292,302.97	277,015	15,287.97	5.52	1,202,144.00	818,246	383,898.00	46.92
2	Fuel Cost of Power Sold	(8,919,057.63)	(2,461,000)	(6,458,057.63)	(262.42)	(48,819,929.32)	(15,600,000)	(33,219,929.32)	(212.95)
3	Fuel Cost - Purchased Power	13,601,086.97	4,944,000	8,657,086.97	175.10	62,887,134.09	20,397,000	42,490,134.09	208.32
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	422,653.66	0	422,653.66	100.00	2,327,631.92	0	2,327,631.92	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	3,284,575.00	0	3,284,575.00	100.00	15,721,881.00	0	15,721,881.00	100.00
6	Total Fuel & Net Power Transactions	41,642,135.73	53,184,008	(11,541,872.32)	(21.70)	164,127,377.70	224,090,142	(59,962,764.70)	(26.76)
7	AdjustmentsTo Fuel Cost*	51,503.26	0	51,503.26	100.00	73,955.05	0	73,955.05	100.00
8	Adj. Total Fuel & Net Power Transactions	41,693,638.99	53,184,008	(11,490,369.01)	(21.60)	164,201,332.75	224,090,142	(59,888,809.65)	(26.73)
B.	*KWH Sales*								
1	Jurisdictional Sales	991,336,935	1,029,397,000	(38,060,065)	(3.70)	4,013,392,117	4,450,246,000	(436,853,883)	(9.82)
2	Non-Jurisdictional Sales	27,942,808	33,914,000	(5,971,192)	(17.61)	132,468,561	155,002,000	(22,533,439)	(14.54)
3	Total Territorial Sales	1,019,279,743	1,063,311,000	(44,031,257)	(4.14)	4,145,860,678	4,605,248,000	(459,387,322)	(9.98)
4	Juris. Sales as % of Total Terr. Sales	97.2586	96.8105	0.4481	0.46	96.8048	96.6342	0.1706	0.18

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	45,769,430.01	47,522,113	(1,752,682.50)	(3.69)	188,980,984.84	211,162,286	(22,181,301.56)	(10.50)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	1,491,620.90	1,491,621	0.00	0.00	2,466,331.86	2,466,332	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(268,769.40)	(268,769)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	47,207,297.03	48,959,980	(1,752,682.97)	(3.58)	191,178,547.30	213,359,849	(22,181,301.70)	(10.40)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	41,693,638.99	53,184,008	(11,490,369.01)	(21.60)	164,201,332.75	224,090,142	(59,888,809.25)	(26.73)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2586	96.8105	0.4481	0.46	96.8048	96.6342	0.1706	0.18
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	40,611,475.55	51,523,745	(10,912,269.45)	(21.18)	159,117,628.07	216,703,586	(57,585,957.93)	(26.57)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	6,595,821.48	(2,563,765)	9,159,586.48	357.27	32,060,919.23	(3,343,737)	35,404,656.23	1,058.83
8	Interest Provision for the Month	3,845.71	(1,647)	5,492.71	333.50	10,622.79	(4,974)	15,596.79	313.57
9	Beginning True-Up & Interest Provision	34,425,857.56	(13,809,195)	48,235,052.56	349.30	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(1,491,620.90)	(1,491,621)	0.00	0.00	(2,466,331.86)	(2,466,332)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	39,533,903.85	(17,866,228)	57,400,131.85	321.28	39,533,903.85	(17,866,228)	57,400,131.85	321.28
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	39,533,903.85	(17,866,228)	57,400,131.85	321.28	39,533,903.85	(17,866,228)	57,400,131.85	321.28

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	34,425,857.56	(13,809,195)	48,235,052.56	(349.30)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	39,530,058.14	(17,864,581)	57,394,639.14	(321.28)
3	Total of Beginning & Ending True-Up Amts.	73,955,915.70	(31,673,776)	105,629,691.70	(333.49)
4	Average True-Up Amount	36,977,957.85	(15,836,888)	52,814,845.85	(333.49)
	Interest Rate				
5	1st Day of Reporting Business Month	0.12	0.12	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.13	0.13	0.0000	
7	Total (D5+D6)	0.25	0.25	0.0000	
8	Annual Average Interest Rate	0.13	0.13	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0104	0.0104	0.0000	
10	Interest Provision (D4*D9)	3,845.71	(1,647)	5,492.71	(333.50)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0007		

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	310,167	55,352	254,815	460.35	725,965	276,248	449,717	162.79
2	COAL	23,219,050	40,320,323	(17,101,273)	(42.41)	86,374,004	166,654,614	(80,280,610)	(48.17)
3	GAS	8,377,825	10,267,227	(1,889,402)	(18.40)	41,919,205	52,077,407	(10,158,202)	(19.51)
4	GAS (B.L.)	1,282,585	0	1,282,585	100.00	2,588,615	-	2,588,615	100.00
5	LANDFILL GAS	63,251	58,106	5,145	8.85	307,946	284,874	23,072	8.10
6	OIL - C.T.	0	0	0	0.00	94,924	0	94,924	100.00
7	TOTAL ($)	33,252,878	50,701,008	(17,448,130)	(34.41)	132,010,659	219,293,143	(87,282,484)	(39.80)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	458,798	838,239	(379,441)	(45.27)	1,709,144	3,330,929	(1,621,785)	(48.69)
10	GAS	355,344	219,090	136,254	62.19	1,860,077	1,425,731	434,346	30.46
11	LANDFILL GAS	2,175	2,240	(65)	(2.90)	10,806	10,982	(176)	(1.60)
12	OIL - C.T.	23	0	23	100.00	332	0	332	100.00
13	TOTAL (MWH)	816,340	1,059,569	(243,229)	(22.96)	3,580,359	4,767,642	(1,187,283)	(24.90)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	2,444	408	2,036	499.17	5,710	2,039	3,671	180.00
15	COAL (TONS)	217,482	392,378	(174,896)	(44.57)	794,986	1,568,020	(773,034)	(49.30)
16	GAS (MCF) (1)	2,654,804	1,779,118	875,686	49.22	13,709,267	9,907,996	3,801,271	38.37
17	OIL - C.T. (BBL)	0	0	0	0.00	930	0	930	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,527,235	9,046,366	(3,519,131)	(38.90)	19,985,924	36,135,200	(16,149,276)	(44.69)
19	GAS - Generation (1)	2,239,200	1,832,491	406,709	22.19	12,877,654	10,205,234	2,672,420	26.19
20	OIL - C.T.	0	0	0	0.00	5,406	0	5,406	100.00
21	TOTAL (MMBTU)	7,766,435	10,878,857	(3,112,422)	(28.61)	32,868,984	46,340,434	(13,471,450)	(29.07)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	56.20	79.11	(22.91)	(28.96)	47.74	69.87	(22.13)	(31.67)
24	GAS	43.53	20.68	22.85	110.49	51.95	29.90	22.05	73.75
25	LANDFILL GAS	0.27	0.21	0.06	28.57	0.30	0.23	0.07	30.43
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	126.91	135.71	(8.80)	(6.48)	127.14	135.46	(8.32)	(6.14)
29	COAL ($/TON)	106.76	102.76	4.00	3.89	108.65	106.28	2.37	2.23
30	GAS ($/MCF) (1)	3.53	5.62	(2.09)	(37.19)	3.16	5.17	(2.01)	(38.88)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	102.07	0.00	102.07	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.49	4.46	0.03	0.67	4.49	4.62	(0.13)	(2.81)
33	GAS - Generation (1)	3.61	5.45	(1.84)	(33.76)	3.16	5.02	(1.86)	(37.05)
34	OIL - C.T.	0.00	0.00	0.00	0.00	17.56	0.00	17.56	100.00
35	TOTAL ($/MMBTU)	4.24	4.63	(0.39)	(8.42)	3.97	4.71	(0.74)	(15.71)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	12,047	10,792	1,255	11.63	11,694	10,848	846	7.80
37	GAS - Generation (1)	6,468	8,588	(2,120)	(24.69)	7,066	7,244	(178)	(2.46)
38	OIL - C.T.	0	0	0	0.00	16,283	0	16,283	100.00
39	TOTAL (BTU/KWH)	9,648	10,345	(697)	(6.74)	9,306	9,777	(471)	(4.82)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.41	4.82	0.59	12.24	5.25	5.01	0.24	4.79
41	GAS	2.36	4.69	(2.33)	(49.68)	2.25	3.65	(1.40)	(38.36)
42	LANDFILL GAS	2.91	2.59	0.32	12.36	2.85	2.59	0.26	10.04
43	OIL - C.T.	0.00	0.00	0.00	0.00	28.59	0.00	28.59	100.00
44	TOTAL (¢/KWH)	4.07	4.79	(0.72)	(15.03)	3.69	4.60	(0.91)	(19.78)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(855)	(1.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,015	0	0	0.00	0.00
3									Gas-S	0	1,015	0	0		0.00
4									Oil-S	0	137,918	0	0		0.00
5	Crist 5		75	26,418	62.7	99.8	62.8	10,786	Coal	11,944	11,929	284,950	1,265,206	4.79	105.93
6				8,586					Gas-G	0	1,015	0	0	0.00	0.00
7									Gas-S	0	1,015	0	0		0.00
8									Oil-S	74	137,918	426	8,213		110.99
9	Crist 6		291	156,777	72.4	100.0	72.4	9,926	Coal	65,157	11,941	1,556,124	6,902,391	4.40	105.93
10				0					Gas-G	0	1,015	0	0	0.00	0.00
11									Gas-S	0	1,015	0	0		0.00
12									Oil-S	0	137,918	2	30		0.00
13	Crist 7		465	104,870	38.8	99.9	59.7	12,627	Coal	55,569	11,915	1,324,227	5,886,600	5.61	105.93
14				29,252					Gas-G	0	1,015	0	0	0.00	0.00
15									Gas-S	444,340	1,015	451,005	1,282,585		2.89
16									Oil-S	34	137,918	195	3,748		110.24
17	Scholz 1		46	(296)	(0.9)	43.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	138,460	0	0		0.00
19	Scholz 2		46	(157)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	138,460	0	0		0.00
21	Smith 1		162	32,249	26.8	96.9	46.2	10,747	Coal	15,013	11,543	346,584	1,849,122	5.73	123.17
22									Oil-S	261	138,066	1,514	33,977		130.18
23	Smith 2		195	50,981	35.1	99.9	40.0	10,740	Coal	23,767	11,519	547,533	2,927,323	5.74	123.17
24									Oil-S	99	138,066	574	12,881		130.11
25	Smith 3		558	308,334	74.3	98.2	89.1	7,262	Gas-G	2,210,464	1,013	2,239,200	8,085,522	2.62	3.66
26	Smith A	(2)	36	23	0.1	100.0	46.2	0	Oil	0	138,370	0	0	0.00	0.00
27	Other Generation			9,172									292,303	3.19	0.00
28	Perdido			2,175					Landfill Gas				63,251	2.91	0.00
29	Daniel 1	(1)	255	38,136	20.1	78.5	56.1	11,634	Coal	19,620	11,307	443,691	1,833,272	4.81	93.44
30									Oil-S	1,747	139,683	10,251	222,233		127.21
31	Daniel 2	(1)	255	50,675	26.7	100.0	46.2	11,027	Coal	26,412	10,579	558,817	2,467,926	4.87	93.44
32									Oil-S	229	139,683	1,342	29,085		127.01
33	Total		2,459	816,340	44.6	96.1	59.5	9,648				7,766,435	33,165,668	4.06	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	91,269	
	Recoverable Fuel	33,252,878	4.07

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	2,991	1,226	1,765	143.96	5,300	6,130	(830)	(13.54)
3	UNIT COST ($/BBL)	127.35	135.18	(7.83)	(5.79)	131.00	135.18	(4.18)	(3.09)
4	AMOUNT ($)	380,898	165,728	215,170	129.83	694,307	828,640	(134,333)	(16.21)
5	*BURNED :*								
6	UNITS (BBL)	2,486	408	2,078	509.31	5,905	2,040	3,865	189.46
7	UNIT COST ($/BBL)	126.99	135.67	(8.68)	(6.40)	127.38	135.42	(8.04)	(5.94)
8	AMOUNT ($)	315,696	55,352	260,344	470.34	752,201	276,248	475,953	172.29
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	4,782	19,396	(14,614)	(75.35)	4,782	19,396	(14,614)	(75.35)
11	UNIT COST ($/BBL)	121.55	61.83	59.72	96.59	121.55	61.83	59.72	96.59
12	AMOUNT ($)	581,263	1,199,184	(617,921)	(51.53)	581,263	1,199,184	(617,921)	(51.53)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	196,110	389,446	(193,336)	(49.64)	831,392	1,292,418	(461,026)	(35.67)
16	UNIT COST ($/TON)	108.75	100.63	8.12	8.07	108.17	108.56	(0.39)	(0.36)
17	AMOUNT ($)	21,326,431	39,189,802	(17,863,371)	(45.58)	89,930,509	140,301,358	(50,370,849)	(35.90)
18	*BURNED :*								
19	UNITS (TONS)	217,482	392,378	(174,896)	(44.57)	794,986	1,568,020	(773,034)	(49.30)
20	UNIT COST ($/TON)	106.36	102.76	3.60	3.50	107.88	106.28	1.60	1.51
21	AMOUNT ($)	23,131,839	40,320,323	(17,188,484)	(42.63)	85,759,406	166,654,613	(80,895,207)	(48.54)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	937,754	632,137	305,617	48.35	937,754	632,137	305,617	48.35
24	UNIT COST ($/TON)	104.93	108.75	(3.82)	(3.51)	104.93	108.75	(3.82)	(3.51)
25	AMOUNT ($)	98,394,944	68,747,676	29,647,268	43.12	98,394,944	68,747,676	29,647,268	43.12
26	DAYS SUPPLY	45	31	14	45.16	45	31	14	45.16
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,690,205	1,832,491	857,714	46.81	13,907,710	10,205,234	3,702,476	36.28
29	UNIT COST ($/MMBTU)	3.61	5.45	(1.84)	(33.76)	3.11	5.15	(2.04)	(39.61)
30	AMOUNT ($)	9,706,008	9,990,212	(284,204)	(2.84)	43,192,473	52,548,615	(9,356,142)	(17.80)
31	*BURNED :*								
32	UNITS (MMBTU)	2,690,205	1,832,491	857,714	46.81	13,900,227	10,205,234	3,694,993	36.21
33	UNIT COST ($/MMBTU)	3.48	5.45	(1.97)	(36.15)	3.12	5.15	(2.03)	(39.42)
34	AMOUNT ($)	9,368,107	9,990,212	(622,105)	(6.23)	43,305,675	52,548,615	(9,242,940)	(17.59)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	1,037,061	0	1,037,061	100.00	1,037,061	0	1,037,061	100.00
37	UNIT COST ($/MMBTU)	3.61	0.00	3.61	100.00	3.61	0.00	3.61	100.00
38	AMOUNT ($)	3,744,721	0	3,744,721	100.00	3,744,721	0	3,744,721	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	710	0	710	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	139.29	0.00	139.00	100.00
42	AMOUNT ($)	0	0	0	0.00	98,899	0	98,899	100.00
43	*BURNED :*								
44	UNITS (BBL)	0	0	0	0.00	930	0	930	100.00
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	102.07	0.00	102.07	100.00
46	AMOUNT ($)	0	0	0	0.00	94,924	0	94,924	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,606	7,143	(537)	(7.52)	6,606	7,143	(537)	(7.52)
49	UNIT COST ($/BBL)	103.90	97.52	6.38	6.54	103.90	97.52	6.38	6.54
50	AMOUNT ($)	686,369	696,578	(10,209)	(1.47)	686,369	696,578	(10,209)	(1.47)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
						(a)	(b)		
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		45,332,000	0	45,332,000	4.21	4.59	1,907,000	2,079,000
2	Various	Economy Sales	12,922,000	0	12,922,000	3.78	4.29	489,000	554,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	65,000	0
4	TOTAL ESTIMATED SALES		58,254,000	0	58,254,000	4.22	4.52	2,461,000	2,633,000
	ACTUAL								
5	Southern Company Interchange		363,212,419	0	363,212,419	2.41	2.70	8,759,041	9,810,795
6	A.E.C.	External	428,937	0	428,937	3.48	4.31	14,945	18,476
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	6,304	0	6,304	3.41	5.50	215	347
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	17,550	0	17,550	3.68	4.99	647	876
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	120	0
13	CARGILE	External	182,691	0	182,691	2.93	4.77	5,351	8,714
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	12,349	0	12,349	2.77	3.52	343	435
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	18,005	0	18,005	2.13	1.73	384	312
19	EAGLE EN	External	51,541	0	51,541	2.61	3.62	1,344	1,867
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	9,164	0	9,164	3.32	4.58	304	420
22	ENTERGY	External	5,321,994	0	5,321,994	3.28	7.37	174,796	392,227
23	FPC	External	411,777	0	411,777	3.29	5.08	13,559	20,901
24	FPL	External	291,418	0	291,418	2.97	3.84	8,644	11,194
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	61,418	0	61,418	2.75	4.10	1,691	2,516
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	102,501	0	102,501	2.30	3.16	2,354	3,237
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	0	0	0	0.00	0.00	(7)	0
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	75,717	0	75,717	2.45	3.56	1,852	2,697
36	ORLANDO	External	19,497	0	19,497	2.65	3.73	516	728
37	PJM	External	1,870,308	0	1,870,308	2.18	3.10	40,752	58,026
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	0	0	0	0.00	0.00	(26)	0
40	SEC	External	269,141	0	269,141	2.49	3.12	6,697	8,396
41	SEPA	External	31,913	0	31,913	2.20	2.91	703	929
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	30,225	0	30,225	3.46	4.73	1,045	1,430
44	TEA	External	784,289	0	784,289	2.16	3.17	16,921	24,868
45	TECO	External	0	0	0	0.00	0.00	0	0
46	TENASKA	External	16,248	0	16,248	3.64	4.76	591	773
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	64,211	0	64,211	2.50	3.89	1,608	2,500
49	WRI	External	31,847	0	31,847	3.50	5.38	1,115	1,713
50	Less: Flow-Thru Energy		(10,005,637)	0	(10,005,637)	2.95	2.95	(294,905)	(294,905)
51	SEPA		956,384	956,384	0	0.00	0.00	0	0
52	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	158,458	158,458
53	Other transactions including adj.		283,044,779	184,185,735	98,859,044	0.00	0.00	0	0
54	TOTAL ACTUAL SALES		647,316,990	185,142,119	462,174,871	1.38	1.56	8,919,058	10,079,472
55	Difference in Amount		589,062,990	185,142,119	403,920,871	(2.84)	(2.96)	6,458,058	7,446,472
56	Difference in Percent		1,011.20	0.00	693.38	(67.30)	(65.49)	262.42	282.81

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 52

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) ¢ / KWH (a) FUEL COST	(6) ¢ / KWH (b) TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		357,906,000	0	357,906,000	3.59	3.94	12,861,000	14,088,000
2	Various	Economy Sales	66,679,000	0	66,679,000	3.61	4.04	2,408,000	2,693,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	331,000	0
4	TOTAL ESTIMATED SALES		424,585,000	0	424,585,000	3.67	3.95	15,600,000	16,781,000
	ACTUAL								
5	Southern Company Interchange		2,152,537,568	0	2,152,537,568	2.25	2.47	48,536,310	53,120,093
6	A.E.C.	External	994,711	0	994,711	2.90	3.70	28,838	36,818
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	6,304	0	6,304	3.41	5.50	215	347
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	17,550	0	17,550	3.68	4.99	647	876
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	139,085	0	139,085	3.10	3.56	4,311	4,955
13	CARGILE	External	1,521,095	0	1,521,095	2.25	3.11	34,253	47,275
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	387,557	0	387,557	2.04	3.03	7,916	11,738
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	2,661,220	0	2,661,220	1.94	2.66	51,502	70,680
19	EAGLE EN	External	398,346	0	398,346	2.25	3.37	8,958	13,429
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	39,969	0	39,969	2.06	3.88	823	1,551
22	ENTERGY	External	8,863,306	0	8,863,306	3.04	6.78	269,544	600,649
23	FPC	External	471,117	0	471,117	3.35	5.21	15,799	24,533
24	FPL	External	2,560,006	0	2,560,006	2.45	3.71	62,665	95,044
25	JARON	External	26,000	0	26,000	1.66	2.20	431	572
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	332,641	0	332,641	2.47	3.42	8,217	11,381
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	583,919	0	583,919	2.03	2.94	11,834	17,160
32	NCEMC	External	12,674	0	12,674	1.90	2.80	241	355
33	NCMPA1	External	278,971	0	278,971	2.46	2.93	6,873	8,185
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	334,776	0	334,776	2.22	3.30	7,434	11,054
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	6,590,195	0	6,590,195	1.94	2.94	127,595	193,586
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	1,727,304	0	1,727,304	3.07	4.48	53,109	77,339
40	SEC	External	594,503	0	594,503	2.23	2.92	13,231	17,355
41	SEPA	External	278,627	0	278,627	2.29	3.27	6,390	9,124
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	42,575	0	42,575	3.08	4.26	1,311	1,814
44	TEA	External	3,598,988	0	3,598,988	1.99	2.90	71,687	104,379
45	TECO	External	245,612	0	245,612	2.35	3.76	5,761	9,231
46	TENASKA	External	27,622	0	27,622	3.15	4.29	871	1,186
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	618,913	0	618,913	2.16	3.35	13,374	20,711
49	WRI	External	109,847	0	109,847	2.33	3.23	2,562	3,546
50	Less: Flow-Thru Energy		(33,448,609)	0	(33,448,609)	2.44	2.44	(815,258)	(815,258)
51	SEPA		6,668,552	6,668,552	0	0.00	0.00	0	0
52	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	279,680	279,680
53	Other transactions including adj.		1,165,072,388	846,941,424	318,130,964	0.00	0.00	0	0
54	TOTAL ACTUAL SALES		3,324,467,250	853,609,976	2,470,857,274	1.47	1.62	48,819,930	53,703,688
55	Difference in Amount		2,899,882,250	853,609,976	2,046,272,274	(2.20)	(2.33)	33,219,930	36,922,688
56	Difference in Percent		682.99	0.00	481.95	(59.95)	(58.99)	212.95	220.03

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 52

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: MAY 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

CURRENT MONTH

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	5,149
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	15,776,000	0	0	0	2.62	2.62	413,667
6	International Paper	COG 1	145,000	0	0	0	2.65	2.65	3,839
7	TOTAL		15,921,000	0	0	0	2.65	2.65	422,654

PERIOD-TO-DATE

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	17
5	Ascend Performance Materials	COG 1	82,297,000	0	0	0	2.43	2.43	2,000,173
6	International Paper	COG 1	417,000	0	0	0	2.49	2.49	10,371
7	TOTAL		86,940,000	0	0	0	2.68	2.68	2,327,632

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	117,541,000	3.78	4,446,000	478,832,000	3.97	19,004,000
2	Economy Energy	5,779,000	4.38	253,000	23,520,000	4.01	944,000
3	Other Purchases	4,811,000	5.09	245,000	8,610,000	5.21	449,000
4	TOTAL ESTIMATED PURCHASES	128,131,000	3.86	4,944,000	510,962,000	3.99	20,397,000
	ACTUAL						
5	Southern Company Interchange	68,826,292	2.85	1,962,774	355,099,081	2.50	8,885,958
6	Non-Associated Companies	12,604,692	2.83	356,797	87,293,089	2.93	2,559,556
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	536,266,000	2.15	11,539,785	2,463,500,000	2.12	52,190,978
9	Other Wheeled Energy	124,106,000	0.00	N/A	440,344,000	0.00	N/A
10	Other Transactions	175,807,259	0.04	69,591	755,915,137	0.02	157,272
11	Less: Flow-Thru Energy	(10,005,637)	3.28	(327,860)	(33,448,609)	2.71	(906,629)
12	TOTAL ACTUAL PURCHASES	907,604,606	1.50	13,601,087	4,068,702,698	1.55	62,887,135
13	Difference in Amount	779,473,606	(2.36)	8,657,087	3,557,740,698	(2.44)	42,490,135
14	Difference in Percent	608.34	(61.14)	175.10	696.28	(61.15)	208.32

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692			1,227,653
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759			8,217,948
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)			(26,378)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ -	$ 8,191,570
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ 1,484,274**		**$ 2,071,953**		$ -	**$ 9,419,223**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													1,227,653
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													8,217,948
2 Other Confidential Agreements	Other	Varies	Varies													(26,378)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 8,191,570
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 9,419,223

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

JUNE 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	34,212,567	50,893,027	(16,680,460)	(32.78)	795,576,000	1,113,412,000	(317,836,000)	(28.55)	4.3004	4.5709	(0.27)	(5.92)
2	Hedging Settlement Costs (A2)	3,610,712	0	3,610,712	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	58,038	0	58,038	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	37,881,317	50,893,027	(13,011,710)	(25.57)	795,576,000	1,113,412,000	(317,836,000)	(28.55)	4.7615	4.5709	0.19	4.17
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	14,900,168	7,859,000	7,041,168	89.59	915,955,893	185,462,000	730,493,893	393.88	1.6267	4.2375	(2.61)	(61.61)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	413,783	0	413,783	100.00	14,289,000	0	14,289,000	100.00	2.8958	0.0000	2.90	0.00
12	TOTAL COST OF PURCHASED POWER	15,313,951	7,859,000	7,454,951	94.86	930,244,893	185,462,000	744,782,893	401.58	1.6462	4.2375	(2.59)	(61.15)
13	Total Available MWH (Line 5 + Line 12)	53,195,268	58,752,027	(5,556,759)	(9.46)	1,725,820,893	1,298,874,000	426,946,893	32.87				
14	Fuel Cost of Economy Sales (A6)	(148,740)	(398,000)	249,260	(62.63)	(4,525,923)	(9,279,000)	4,753,077	(51.22)	(3.2864)	(4.2893)	1.00	23.38
15	Gain on Economy Sales (A6)	(50,076)	(47,000)	(3,076)	6.54	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(10,607,202)	(1,373,000)	(9,234,202)	672.56	(613,270,418)	(28,689,000)	(584,581,418)	2,037.65	(1.7296)	(4.7858)	3.06	63.86
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(10,806,018)	(1,818,000)	(8,988,018)	494.39	(617,796,341)	(37,968,000)	(579,828,341)	1,527.15	(1.7491)	(4.7882)	3.04	63.47
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	42,389,250	56,934,027	(14,544,777)	(25.55)	1,108,024,552	1,260,906,000	(152,881,448)	(12.12)	3.8257	4.5153	(0.69)	(15.27)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	68,421	75,586	(7,165)	(9.48)	1,788,466	1,674,000	114,466	6.84	3.8257	4.5153	(0.69)	(15.27)
22	T & D Losses *	1,797,917	3,624,567	(1,826,650)	(50.40)	46,995,777	80,273,000	(33,277,223)	(41.46)	3.8257	4.5153	(0.69)	(15.27)
23	TERRITORIAL KWH SALES	42,389,250	56,934,027	(14,544,777)	(25.55)	1,059,240,309	1,178,959,000	(119,718,691)	(10.15)	4.0019	4.8292	(0.83)	(17.13)
24	Wholesale KWH Sales	1,153,581	1,793,195	(639,614)	(35.67)	28,825,730	37,133,000	(8,307,270)	(22.37)	4.0019	4.8291	(0.83)	(17.13)
25	Jurisdictional KWH Sales	41,235,669	55,140,832	(13,905,163)	(25.22)	1,030,414,579	1,141,826,000	(111,411,421)	(9.76)	4.0019	4.8292	(0.83)	(17.13)
26	Jurisdictional Loss Multiplier	1.0015	1.0007							1.0015	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	41,297,523	55,179,431	(13,881,908)	(25.16)	1,030,414,579	1,141,826,000	(111,411,421)	(9.76)	4.0079	4.8326	(0.82)	(17.07)
28	TRUE-UP	(1,491,621)	(1,491,621)	0	0.00	1,030,414,579	1,141,826,000	(111,411,421)	(9.76)	(0.1448)	(0.1306)	(0.01)	10.87
29	TOTAL JURISDICTIONAL FUEL COST	39,805,902	53,687,810	(13,881,908)	(25.86)	1,030,414,579	1,141,826,000	(111,411,421)	(9.76)	3.8631	4.7020	(0.84)	(17.84)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.8659	4.7054	(0.84)	(17.84)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	1,030,414,579	1,141,826,000	(111,411,421)	(9.76)	0.0052	0.0047	0.00	10.64
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.8711	4.7101	(0.84)	(17.81)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.871	4.710		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: JUNE 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 34,212,567
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	58,038
4	Hedging Settlement Costs	Schedule A-2, Line A-5	3,610,712
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	14,900,168
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	413,783
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(10,806,018)
10	Total Fuel and Net Power Transactions		$ 42,389,250

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	166,223,227	270,186,169	(103,962,942)	(38.48)	4,375,935,000	5,881,054,000	(1,505,119,000)	(25.59)	3.7986	4.5942	(0.80)	(17.32)
2	Hedging Settlement Costs (A2)	19,332,593	0	19,332,593	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	131,993	0	131,993	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	185,687,813	270,186,169	(84,498,356)	(31.27)	4,375,935,000	5,881,054,000	(1,505,119,000)	(25.59)	4.2434	4.5942	(0.35)	(7.64)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	77,787,303	28,256,000	49,531,303	175.29	4,984,658,591	696,424,000	4,288,234,591	615.75	1.5605	4.0573	(2.50)	(61.54)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	2,741,415	0	2,741,415	100.00	101,229,000	0	101,229,000	100.00	2.7081	0.0000	2.71	0.00
12	TOTAL COST OF PURCHASED POWER	80,528,718	28,256,000	52,272,718	185.00	5,085,887,591	696,424,000	4,389,463,591	630.29	1.5834	4.0573	(2.47)	(60.97)
13	Total Available MWH (Line 5 + Line 12)	266,216,531	298,442,169	(32,225,638)	(10.80)	9,461,822,591	6,577,478,000	2,884,344,591	43.85				
14	Fuel Cost of Economy Sales (A6)	(967,938)	(2,806,000)	1,838,062	(65.50)	(38,163,274)	(75,958,000)	37,794,726	(49.76)	(2.5363)	(3.6941)	1.16	31.34
15	Gain on Economy Sales (A6)	(329,756)	(378,000)	48,244	(12.76)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(58,328,254)	(14,234,000)	(44,094,254)	309.78	(3,904,100,317)	(386,595,000)	(3,517,505,317)	909.87	(1.4940)	(3.6819)	2.19	59.42
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(59,625,948)	(17,418,000)	(42,207,948)	242.32	(3,942,263,591)	(462,553,000)	(3,479,710,591)	752.28	(1.5125)	(3.7656)	2.25	59.83
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	206,590,583	281,024,169	(74,433,586)	(26.49)	5,519,559,000	6,114,925,000	(595,366,000)	(9.74)	3.7429	4.5957	(0.85)	(18.56)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	364,847	502,632	(137,785)	(27.41)	9,747,714	10,937,000	(1,189,286)	(10.87)	3.7429	4.5957	(0.85)	(18.56)
22	T & D Losses *	11,405,002	14,696,175	(3,291,173)	(22.39)	304,710,299	319,781,000	(15,070,701)	(4.71)	3.7429	4.5957	(0.85)	(18.56)
23	TERRITORIAL KWH SALES	206,590,582	281,024,169	(74,433,587)	(26.49)	5,205,100,987	5,784,207,000	(579,106,013)	(10.01)	3.9690	4.8585	(0.89)	(18.31)
24	Wholesale KWH Sales	6,405,047	9,331,337	(2,926,290)	(31.36)	161,294,291	192,135,000	(30,840,709)	(16.05)	3.9710	4.8567	(0.89)	(18.24)
25	Jurisdictional KWH Sales	200,185,535	271,692,832	(71,507,297)	(26.32)	5,043,806,696	5,592,072,000	(548,265,304)	(9.80)	3.9689	4.8585	(0.89)	(18.31)
26	Jurisdictional Loss Multiplier***	1.0015	1.0007							1.0015	1.0007		
27	Jurisdictional KWH Sales Adj. for Line Losses	200,415,152	271,863,017	(71,467,865)	(26.29)	5,043,806,696	5,592,072,000	(548,265,304)	(9.80)	3.9735	4.8619	(0.89)	(18.27)
28	TRUE-UP	(3,957,954)	(3,957,954)	0	0.00	5,043,806,696	5,592,072,000	(548,265,304)	(9.80)	(0.0785)	(0.0708)	(0.01)	10.88
29	TOTAL JURISDICTIONAL FUEL COST	196,457,198	267,925,063	(71,467,865)	(26.67)	5,043,806,696	5,592,072,000	(548,265,304)	(9.80)	3.8950	4.7911	(0.90)	(18.70)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.8978	4.7945	(0.90)	(18.70)
32	GPIF Reward / (Penalty)	322,758	322,758	0	0.00	5,043,806,696	5,592,072,000	(548,265,304)	(9.80)	0.0064	0.0058	0.00	10.34
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9042	4.8003	(0.90)	(18.67)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.904	4.800		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$	*DIFFERENCE*			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	33,934,668.99	50,624,933	(16,690,263.69)	(32.97)	164,743,185.00	269,099,829	(104,356,644.08)	(38.78)
1a	Other Generation	277,898.00	268,094	9,804.00	3.66	1,480,042.00	1,086,340	393,702.00	36.24
2	Fuel Cost of Power Sold	(10,806,018.15)	(1,818,000)	(8,988,018.15)	(494.39)	(59,625,947.47)	(17,418,000)	(42,207,947.47)	(242.32)
3	Fuel Cost - Purchased Power	14,900,168.09	7,859,000	7,041,168.09	89.59	77,787,302.18	28,256,000	49,531,302.18	175.29
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	413,783.14	0	413,783.14	100.00	2,741,415.06	0	2,741,415.06	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	3,610,712.00	0	3,610,712.00	100.00	19,332,593.00	0	19,332,593.00	100.00
6	Total Fuel & Net Power Transactions	42,331,212.07	56,934,027	(14,602,814.61)	(25.65)	206,458,589.77	281,024,169	(74,565,579.31)	(26.53)
7	AdjustmentsTo Fuel Cost*	58,038.06	0	58,038.06	100.00	131,993.11	0	131,993.11	100.00
8	Adj. Total Fuel & Net Power Transactions	42,389,250.13	56,934,027	(14,544,776.87)	(25.55)	206,590,582.88	281,024,169	(74,433,586.20)	(26.49)
B.	*KWH Sales*								
1	Jurisdictional Sales	1,030,414,579	1,141,826,000	(111,411,421)	(9.76)	5,043,806,696	5,592,072,000	(548,265,304)	(9.80)
2	Non-Jurisdictional Sales	28,825,730	37,133,000	(8,307,270)	(22.37)	161,294,291	192,135,000	(30,840,709)	(16.05)
3	Total Territorial Sales	1,059,240,309	1,178,959,000	(119,718,691)	(10.15)	5,205,100,987	5,784,207,000	(579,106,013)	(10.01)
4	Juris. Sales as % of Total Terr. Sales	97.2786	96.8504	0.4282	0.44	96.9012	96.6783	0.2229	0.23

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	43,394,369.06	52,712,397	(9,318,028.23)	(17.68)	232,375,353.90	263,874,684	(31,499,329.79)	(11.94)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	1,491,620.90	1,491,621	0.00	0.00	3,957,952.76	3,957,953	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(322,523.28)	(322,523)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	44,832,236.08	54,150,264	(9,318,027.92)	(17.21)	236,010,783.38	267,510,113	(31,499,329.62)	(11.78)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	42,389,250.13	56,934,027	(14,544,776.87)	(25.55)	206,590,582.88	281,024,169	(74,433,586.12)	(26.49)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2786	96.8504	0.4282	0.44	96.9012	96.6783	0.2229	0.23
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	41,297,522.58	55,179,431	(13,881,908.42)	(25.16)	200,415,150.65	271,883,017	(71,467,866.35)	(26.29)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,534,713.50	(1,029,167)	4,563,880.50	443.45	35,595,632.73	(4,372,904)	39,968,536.73	914.00
8	Interest Provision for the Month	4,744.99	(2,238)	6,982.99	312.02	15,367.78	(7,212)	22,579.78	313.09
9	Beginning True-Up & Interest Provision	39,533,903.85	(17,866,228)	57,400,131.85	321.28	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(1,491,620.90)	(1,491,621)	0.00	0.00	(3,957,952.76)	(3,957,953)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	41,581,741.44	(20,389,254)	61,970,995.44	303.94	41,581,741.44	(20,389,254)	61,970,995.44	303.94
12	Adjustment*	(11,884.99)	0	(11,884.99)	100.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	41,569,856.45	(20,389,254)	61,959,110.45	303.88	41,569,856.45	(20,389,254)	61,959,110.45	303.88

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

		CURRENT MONTH			
			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	39,533,903.85	(17,866,228)	57,400,131.85	(321.28)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	41,576,996.45	(20,387,016)	61,964,012.45	(303.94)
3	Total of Beginning & Ending True-Up Amts.	81,110,900.30	(38,253,244)	119,364,144.30	(312.04)
4	Average True-Up Amount	40,555,450.15	(19,126,622)	59,682,072.15	(312.04)
	Interest Rate				
5	1st Day of Reporting Business Month	0.13	0.13	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.15	0.15	0.0000	
7	Total (D5+D6)	0.28	0.28	0.0000	
8	Annual Average Interest Rate	0.14	0.14	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0117	0.0117	0.0000	
10	Interest Provision (D4*D9)	4,744.99	(2,238)	6,982.99	(312.02)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0007		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	112,580	55,364	57,216	103.35	838,545	331,612	506,933	152.87
2	COAL	23,845,833	40,448,573	(16,602,740)	(41.05)	110,219,838	207,103,187	(96,883,349)	(46.78)
3	GAS	10,176,645	10,332,904	(156,259)	(1.51)	52,095,850	62,410,311	(10,314,461)	(16.53)
4	GAS (B.L.)	6,420	0	6,420	100.00	2,595,035	-	2,595,035	100.00
5	LANDFILL GAS	62,288	56,186	6,102	10.86	370,234	341,060	29,174	8.55
6	OIL - C.T.	8,801	0	8,801	100.00	103,725	0	103,725	100.00
7	TOTAL ($)	34,212,567	50,893,027	(16,680,460)	(32.78)	166,223,227	270,186,169	(103,962,942)	(38.48)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	434,560	857,088	(422,528)	(49.30)	2,143,704	4,188,017	(2,044,313)	(48.81)
10	GAS	358,883	254,158	104,725	41.20	2,218,960	1,679,889	539,071	32.09
11	LANDFILL GAS	2,108	2,166	(58)	(2.68)	12,914	13,148	(234)	(1.78)
12	OIL - C.T.	25	0	25	100.00	357	0	357	100.00
13	TOTAL (MWH)	795,576	1,113,412	(317,836)	(28.55)	4,375,935	5,881,054	(1,505,119)	(25.59)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	918	408	510	125.04	6,628	2,447	4,181	170.84
15	COAL (TONS)	204,582	398,123	(193,541)	(48.61)	999,568	1,966,143	(966,575)	(49.16)
16	GAS (MCF) (1)	2,662,342	1,761,190	901,152	51.17	16,371,609	11,669,186	4,702,423	40.30
17	OIL - C.T. (BBL)	85	0	85	100.00	1,015	0	1,015	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	4,775,069	9,204,156	(4,429,087)	(48.12)	24,760,993	45,339,356	(20,578,363)	(45.39)
19	GAS - Generation (1)	2,702,689	1,814,025	888,664	48.99	15,580,343	12,019,259	3,561,084	29.63
20	OIL - C.T.	492	0	492	100.00	5,898	0	5,898	100.00
21	TOTAL (MMBTU)	7,478,250	11,018,181	(3,539,931)	(32.13)	40,347,234	57,358,615	(17,011,381)	(29.66)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	54.63	76.98	(22.35)	(29.03)	48.99	71.22	(22.23)	(31.21)
24	GAS	45.11	22.83	22.28	97.59	50.70	28.56	22.14	77.52
25	LANDFILL GAS	0.26	0.19	0.07	36.84	0.30	0.22	0.08	36.36
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	122.64	135.74	(13.10)	(9.65)	126.52	135.50	(8.98)	(6.63)
29	COAL ($/TON)	116.56	101.60	14.96	14.72	110.27	105.33	4.94	4.69
30	GAS ($/MCF) (1)	3.72	5.71	(1.99)	(34.85)	3.25	5.26	(2.01)	(38.21)
31	OIL - C.T. ($/BBL)	103.54	0.00	103.54	100.00	102.19	0.00	102.19	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	5.02	4.40	0.62	14.09	4.59	4.58	0.01	0.22
33	GAS - Generation (1)	3.66	5.55	(1.89)	(34.05)	3.25	5.10	(1.85)	(36.27)
34	OIL - C.T.	17.89	0.00	17.89	100.00	17.59	0.00	17.59	100.00
35	TOTAL ($/MMBTU)	4.53	4.59	(0.06)	(1.31)	4.07	4.69	(0.62)	(13.22)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,988	10,739	249	2.32	11,551	10,826	725	6.70
37	GAS - Generation (1)	7,705	7,296	409	5.61	7,169	7,252	(83)	(1.14)
38	OIL - C.T.	19,680	0	19,680	100.00	16,521	0	16,521	100.00
39	TOTAL (BTU/KWH)	9,522	9,965	(443)	(4.45)	9,346	9,812	(466)	(4.75)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.51	4.73	0.78	16.49	5.30	4.95	0.35	7.07
41	GAS	2.84	4.07	(1.23)	(30.22)	2.35	3.72	(1.37)	(36.83)
42	LANDFILL GAS	2.95	2.59	0.36	13.90	2.87	2.59	0.28	10.81
43	OIL - C.T.	35.20	0.00	35.20	100.00	29.05	0.00	29.05	100.00
44	TOTAL (¢/KWH)	4.30	4.57	(0.27)	(5.91)	3.80	4.59	(0.79)	(17.21)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	5,678	10.5	99.6	56.7	12,908	Coal	3,101	11,817	73,289	355,337	6.26	114.59
2				6					Gas-G	85	1,016	87	247	4.12	2.90
3									Gas-S	298	1,016	303	864		2.90
4									Oil-S	122	139,041	712	13,919		114.09
5	Crist 5		75	28,613	59.6	100.0	59.6	12,012	Coal	14,616	11,758	343,713	1,674,828	5.85	114.59
6				3,552					Gas-G	42,066	1,016	42,739	121,980	3.43	2.90
7									Gas-S	0	1,016	0	0		0.00
8									Oil-S	91	139,041	534	10,432		114.64
9	Crist 6		291	118,456	56.6	88.3	75.9	10,871	Coal	54,819	11,745	1,287,711	6,281,648	5.30	114.59
10				188					Gas-G	2,001	1,016	2,033	5,803	3.09	2.90
11									Gas-S	0	1,016	0	0		0.00
12									Oil-S	0	139,041	0	0		0.00
13	Crist 7		465	150,473	55.3	92.6	59.8	11,064	Coal	70,713	11,772	1,664,896	8,102,981	5.39	114.59
14				34,790					Gas-G	379,404	1,016	385,473	1,100,164	3.16	2.90
15									Gas-S	1,916	1,016	1,947	5,556		2.90
16									Oil-S	68	139,041	396	7,749		113.96
17	Scholz 1		46	(248)	(0.7)	100.0	0.0	0	Coal	11	11,517	242	914	0.00	83.09
18									Oil-S	5	138,460	27	590		118.00
19	Scholz 2		46	(172)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	138,460	0	0		0.00
21	Smith 1		162	52,221	44.8	100.0	44.8	10,743	Coal	24,122	11,629	561,032	2,931,527	5.61	121.53
22									Oil-S	146	137,405	842	18,986		130.04
23	Smith 2		195	(767)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	137,405	0	0		0.00
25	Smith 3		556	312,228	78.0	99.8	90.5	7,278	Gas-G	2,236,572	1,016	2,272,357	8,670,553	2.78	3.88
26	Smith A	(2)	32	25	0.1	100.0	68.9	19,680	Oil	85	138,370	492	8,801	35.20	103.54
27	Other Generation			8,119									277,898	3.42	0.00
28	Perdido			2,108					Landfill Gas				62,288	2.95	0.00
29	Daniel 1	(1)	255	57,769	31.5	100.0	59.3	10,265	Coal	26,430	11,218	592,993	2,532,680	4.38	95.83
30									Oil-S	216	139,012	1,260	27,043		125.20
31	Daniel 2	(1)	255	22,537	12.3	99.9	37.2	10,809	Coal	10,770	11,309	243,594	1,032,017	4.58	95.82
32									Oil-S	270	139,012	1,578	33,860		125.41
33	Total		2,453	795,576	45.0	97.1	58.3	9,522				7,478,250	33,278,665	4.18	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	118,308	
N/A	Crist Coal Adjustment	734,790	
N/A	Smith Coal Adjustment	84,863	
	Recoverable Fuel	34,212,567	4.30

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	2,029	1,226	803	65.50	7,329	7,356	(27)	(0.37)
3	UNIT COST ($/BBL)	116.50	135.18	(18.68)	(13.82)	126.99	135.18	(8.19)	(6.06)
4	AMOUNT ($)	236,385	165,728	70,657	42.63	930,692	994,368	(63,676)	(6.40)
5	*BURNED :*								
6	UNITS (BBL)	947	408	539	132.11	6,852	2,448	4,404	179.90
7	UNIT COST ($/BBL)	122.81	135.70	(12.89)	(9.50)	126.75	135.46	(8.71)	(6.43)
8	AMOUNT ($)	116,302	55,364	60,938	110.07	868,503	331,612	536,891	161.90
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,865	20,214	(14,349)	(70.99)	5,865	20,214	(14,349)	(70.99)
11	UNIT COST ($/BBL)	119.58	64.78	54.80	84.59	119.58	64.78	54.80	84.59
12	AMOUNT ($)	701,345	1,309,548	(608,203)	(46.44)	701,345	1,309,548	(608,203)	(46.44)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	206,577	398,124	(191,547)	(48.11)	1,037,969	1,690,542	(652,573)	(38.60)
16	UNIT COST ($/TON)	129.17	101.54	27.63	27.21	112.35	106.90	5.45	5.10
17	AMOUNT ($)	26,684,538	40,424,786	(13,740,248)	(33.99)	116,615,047	180,726,144	(64,111,097)	(35.47)
18	*BURNED :*								
19	UNITS (TONS)	204,582	398,123	(193,541)	(48.61)	999,568	1,966,143	(966,575)	(49.16)
20	UNIT COST ($/TON)	116.00	101.60	14.40	14.17	109.54	105.33	4.21	4.00
21	AMOUNT ($)	23,731,583	40,448,573	(16,716,990)	(41.33)	109,490,989	207,103,186	(97,612,197)	(47.13)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	939,748	632,138	307,610	48.66	939,748	632,138	307,610	48.66
24	UNIT COST ($/TON)	107.85	108.72	(0.87)	(0.80)	107.85	108.72	(0.87)	(0.80)
25	AMOUNT ($)	101,347,899	68,723,889	32,624,010	47.47	101,347,899	68,723,889	32,624,010	47.47
26	DAYS SUPPLY	45	31	14	45.16	45	31	14	45.16
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,601,777	1,814,025	787,752	43.43	16,509,487	12,019,259	4,490,228	37.36
29	UNIT COST ($/MMBTU)	3.74	5.55	(1.81)	(32.61)	3.21	5.21	(2.00)	(38.39)
30	AMOUNT ($)	9,723,891	10,064,810	(340,919)	(3.39)	52,916,364	62,613,425	(9,697,061)	(15.49)
31	*BURNED :*								
32	UNITS (MMBTU)	2,704,939	1,814,025	890,914	49.11	16,605,166	12,019,259	4,585,907	38.15
33	UNIT COST ($/MMBTU)	3.66	5.55	(1.89)	(34.05)	3.20	5.21	(2.01)	(38.58)
34	AMOUNT ($)	9,905,167	10,064,810	(159,643)	(1.59)	53,210,842	62,613,425	(9,402,583)	(15.02)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	933,899	0	933,899	100.00	933,899	0	933,899	100.00
37	UNIT COST ($/MMBTU)	3.82	0.00	3.82	100.00	3.82	0.00	3.82	100.00
38	AMOUNT ($)	3,563,446	0	3,563,446	100.00	3,563,446	0	3,563,446	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	710	0	710	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	139.29	0.00	139.00	100.00
42	AMOUNT ($)	0	0	0	0.00	98,899	0	98,899	100.00
43	*BURNED :*								
44	UNITS (BBL)	85	0	85	100.00	1,015	0	1,015	100.00
45	UNIT COST ($/BBL)	103.54	0.00	103.54	100.00	102.19	0.00	102.19	100.00
46	AMOUNT ($)	8,801	0	8,801	100.00	103,725	0	103,725	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,522	7,143	(621)	(8.69)	6,522	7,143	(621)	(8.69)
49	UNIT COST ($/BBL)	103.89	97.52	6.37	6.53	103.89	97.52	6.37	6.53
50	AMOUNT ($)	677,568	696,578	(19,010)	(2.73)	677,568	696,578	(19,010)	(2.73)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

	(1)	(2)	CURRENT MONTH (3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		28,689,000	0	28,689,000	4.79	5.06	1,373,000	1,452,000
2	Various	Economy Sales	9,279,000	0	9,279,000	4.29	4.69	398,000	435,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	47,000	0
4	TOTAL ESTIMATED SALES		37,968,000	0	37,968,000	4.79	4.97	1,818,000	1,887,000
	ACTUAL								
5	Southern Company Interchange		383,250,982	0	383,250,982	2.81	3.12	10,755,724	11,945,655
6	A.E.C.	External	24,372	0	24,372	3.30	4.48	804	1,092
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	(1)	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	92,299	0	92,299	2.45	4.28	2,265	3,952
13	CARGILE	External	157,284	0	157,284	1.67	2.01	2,629	3,168
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	0	0	0	0.00	0.00	0	0
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	6,499	0	6,499	3.36	2.50	219	162
19	EAGLE EN	External	56,615	0	56,615	4.15	4.79	2,352	2,712
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	2,621,141	0	2,621,141	3.89	7.09	101,924	185,783
23	FPC	External	0	0	0	0.00	0.00	16	0
24	FPL	External	0	0	0	0.00	0.00	0	0
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	107,900	0	107,900	4.09	4.95	4,412	5,336
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	45,495	0	45,495	2.72	3.52	1,236	1,601
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	0	0	0	0.00	0.00	0	0
34	NRG	External	3,250	0	3,250	1.74	3.00	57	97
35	OPC	External	35,746	0	35,746	2.20	3.19	788	1,141
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	335,366	0	335,366	2.09	3.08	7,011	10,337
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	0	0	0	0.00	0.00	0	0
40	SEC	External	28,922	0	28,922	2.30	2.87	665	831
41	SEPA	External	35,550	0	35,550	2.31	3.37	821	1,198
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	533,650	0	533,650	2.80	3.81	14,955	20,345
44	TEA	External	419,541	0	419,541	1.92	2.63	8,072	11,032
45	TECO	External	22,293	0	22,293	2.32	3.24	516	723
46	TENASKA	External	0	0	0	0.00	0.00	0	0
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	0	0	0	0.00	0.00	0	0
49	WRI	External	0	0	0	0.00	0.00	1	0
50	Less: Flow-Thru Energy		(4,519,424)	0	(4,519,424)	3.29	3.29	(148,522)	(148,522)
51	SEPA		776,336	776,336	0	0.00	0.00	0	0
52	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	50,076	50,076
53	Other transactions including adj.		233,762,524	201,639,616	32,122,908	0.00	0.00	0	0
54	TOTAL ACTUAL SALES		617,796,341	202,415,952	415,380,389	1.75	1.95	10,806,018	12,046,644
55	Difference in Amount		579,828,341	202,415,952	377,412,389	(3.04)	(3.02)	8,988,018	10,159,644
56	Difference in Percent		1,527.15	0.00	994.03	(63.47)	(60.76)	494.39	538.40

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 52

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢/KWH FUEL COST	(6) (b) ¢/KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		386,595,000	0	386,595,000	3.68	4.02	14,234,000	15,540,000
2	Various	Economy Sales	75,958,000	0	75,958,000	3.89	4.12	2,806,000	3,128,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	378,000	0
4	TOTAL ESTIMATED SALES		462,553,000	0	462,553,000	3.77	4.04	17,418,000	18,668,000
	ACTUAL								
5	Southern Company Interchange		2,535,788,550	0	2,535,788,550	2.34	2.57	59,292,034	65,065,748
6	A.E.C.	External	1,019,083	0	1,019,083	2.91	3.72	29,642	37,910
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	6,304	0	6,304	3.40	5.50	214	347
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	17,550	0	17,550	3.68	4.99	647	876
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	231,384	0	231,384	2.84	3.85	6,576	8,907
13	CARGILE	External	1,678,379	0	1,678,379	2.20	3.01	36,882	50,443
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	387,557	0	387,557	2.04	3.03	7,916	11,738
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	2,667,719	0	2,667,719	1.94	2.66	51,721	70,843
19	EAGLE EN	External	454,961	0	454,961	2.49	3.55	11,310	16,142
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	39,969	0	39,969	2.06	3.88	823	1,551
22	ENTERGY	External	11,484,447	0	11,484,447	3.23	6.85	371,467	786,432
23	FPC	External	471,117	0	471,117	3.36	5.21	15,815	24,533
24	FPL	External	2,560,006	0	2,560,006	2.45	3.71	62,665	95,044
25	JARON	External	26,000	0	26,000	1.66	2.20	431	572
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	440,541	0	440,541	2.87	3.79	12,629	16,717
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	629,414	0	629,414	2.08	2.98	13,070	18,762
32	NCEMC	External	12,674	0	12,674	1.90	2.80	241	355
33	NCMPA1	External	278,971	0	278,971	2.46	2.93	6,873	8,185
34	NRG	External	3,250	0	3,250	1.74	3.00	57	97
35	OPC	External	370,522	0	370,522	2.22	3.29	8,221	12,194
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	6,925,561	0	6,925,561	1.94	2.94	134,606	203,923
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	1,727,304	0	1,727,304	3.07	4.48	53,109	77,339
40	SEC	External	623,425	0	623,425	2.23	2.92	13,896	18,186
41	SEPA	External	314,177	0	314,177	2.30	3.29	7,211	10,323
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	576,225	0	576,225	2.82	3.85	16,266	22,158
44	TEA	External	4,018,529	0	4,018,529	1.98	2.87	79,759	115,412
45	TECO	External	267,905	0	267,905	2.34	3.72	6,277	9,954
46	TENASKA	External	27,622	0	27,622	3.15	4.29	871	1,186
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	618,913	0	618,913	2.16	3.35	13,374	20,711
49	WRI	External	109,847	0	109,847	2.33	3.23	2,563	3,546
50	Less: Flow-Thru Energy		(37,968,033)	0	(37,968,033)	2.54	2.54	(963,780)	(963,780)
51	SEPA		7,444,888	7,444,888	0	0.00	0.00	0	0
52	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	329,756	329,756
53	Other transactions including adj.		1,398,834,912	1,048,581,040	350,253,872	0.00	0.00	0	0
54	TOTAL ACTUAL SALES		3,942,263,591	1,056,025,928	2,886,237,663	1.51	1.67	59,625,948	65,750,332
55	Difference in Amount		3,479,710,591	1,056,025,928	2,423,684,663	(2.26)	(2.37)	42,207,948	47,082,332
56	Difference in Percent		752.28	0.00	523.98	(59.95)	(58.66)	242.32	252.21

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 52

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JUNE 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

CURRENT MONTH

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	14,069,000	0	0	0	2.90	2.90	407,346
6	International Paper	COG 1	220,000	0	0	0	2.93	2.93	6,438
7	TOTAL		14,289,000	0	0	0	2.90	2.90	413,783

PERIOD-TO-DATE

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	17
5	Ascend Performance Materials	COG 1	96,366,000	0	0	0	2.50	2.50	2,407,518
6	International Paper	COG 1	637,000	0	0	0	2.64	2.64	16,808
7	TOTAL		101,229,000	0	0	0	2.71	2.71	2,741,415

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	163,607,000	4.12	6,744,000	642,439,000	4.01	25,748,000
2	Economy Energy	6,322,000	4.73	299,000	29,842,000	4.17	1,243,000
3	Other Purchases	15,533,000	5.25	816,000	24,143,000	5.24	1,265,000
4	TOTAL ESTIMATED PURCHASES	185,462,000	4.24	7,859,000	696,424,000	4.06	28,256,000
	ACTUAL						
5	Southern Company Interchange	73,404,638	3.32	2,435,136	428,503,719	2.64	11,321,094
6	Non-Associated Companies	24,217,541	2.61	632,514	111,510,630	2.86	3,192,070
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	594,768,000	2.01	11,963,348	3,058,268,000	2.10	64,154,326
9	Other Wheeled Energy	58,352,000	0.00	N/A	498,696,000	0.00	N/A
10	Other Transactions	169,733,138	0.02	28,928	925,648,275	0.02	186,200
11	Less: Flow-Thru Energy	(4,519,424)	3.53	(159,758)	(37,968,033)	2.81	(1,066,387)
12	TOTAL ACTUAL PURCHASES	915,955,893	1.63	14,900,168	4,984,658,591	1.56	77,787,303
13	Difference in Amount	730,493,893	(2.61)	7,041,168	4,288,234,591	(2.50)	49,531,303
14	Difference in Percent	393.88	(61.56)	89.59	615.75	(61.58)	175.29

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692	0	0	1,227,653
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ 1,484,274**		**$ 2,071,953**		**$ 7,640,423**	**$ 17,059,646**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice													1,227,653
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies													15,861,933
2 Other Confidential Agreements	Other	Varies	Varies													(29,940)
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 15,831,993
TOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 17,059,646

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

JULY 2012
&
JUNE 2012 REVISED A-2

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2012
CURRENT MONTH

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	39,111,109	33,687,094	5,424,015	16.10	895,385,000	870,196,000	25,189,000	2.89	4.3681	3.8712	0.50	12.84
2	Hedging Settlement Costs (A2)	2,598,950	4,141,760	(1,542,810)	(37.25)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	13,431	0	13,431	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	41,723,490	37,828,854	3,894,636	10.30	895,385,000	870,196,000	25,189,000	2.89	4.6598	4.3472	0.31	7.19
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	18,655,580	14,440,000	4,215,580	29.19	1,024,280,224	629,419,000	394,861,224	62.73	1.8213	2.2942	(0.47)	(20.61)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	674,274	0	674,274	100.00	19,609,000	0	19,609,000	100.00	3.4386	0.0000	3.44	0.00
12	TOTAL COST OF PURCHASED POWER	19,329,854	14,440,000	4,889,854	33.86	1,043,889,224	629,419,000	414,470,224	65.85	1.8517	2.2942	(0.44)	(19.29)
13	Total Available MWH (Line 5 + Line 12)	61,053,344	52,268,854	8,784,490	16.81	1,939,274,224	1,499,615,000	439,659,224	29.32				
14	Fuel Cost of Economy Sales (A6)	(247,658)	(154,000)	(93,658)	60.82	(6,782,208)	(4,477,000)	(2,305,208)	51.49	(3.6516)	(3.4398)	(0.21)	(6.16)
15	Gain on Economy Sales (A6)	(64,150)	(71,000)	6,850	(9.65)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(12,466,880)	(5,629,000)	(6,837,880)	121.48	(675,638,222)	(172,303,000)	(503,335,222)	292.12	(1.8452)	(3.2669)	1.42	43.52
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(12,778,688)	(5,854,000)	(6,924,688)	118.29	(682,420,430)	(176,780,000)	(505,640,430)	286.03	(1.8726)	(3.3115)	1.44	43.45
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	48,274,656	46,414,854	1,859,802	4.01	1,256,853,794	1,322,835,000	(65,981,206)	(4.99)	3.8409	3.5087	0.33	9.47
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	64,838	66,876	(2,038)	(3.05)	1,688,104	1,906,000	(217,896)	(11.43)	3.8409	3.5087	0.33	9.47
22	T & D Losses *	2,202,803	3,299,441	(1,096,638)	(33.24)	57,351,229	94,036,000	(36,684,771)	(39.01)	3.8409	3.5087	0.33	9.47
23	TERRITORIAL KWH SALES	48,274,656	46,414,854	1,859,802	4.01	1,197,814,461	1,226,893,000	(29,078,539)	(2.37)	4.0302	3.7831	0.25	6.53
24	Wholesale KWH Sales	1,314,182	1,376,433	(62,251)	(4.52)	32,608,586	36,383,000	(3,774,414)	(10.37)	4.0302	3.7832	0.25	6.53
25	Jurisdictional KWH Sales	46,960,474	45,038,421	1,922,053	4.27	1,165,205,875	1,190,510,000	(25,304,125)	(2.13)	4.0302	3.7831	0.25	6.53
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	47,030,915	45,105,979	1,924,936	4.27	1,165,205,875	1,190,510,000	(25,304,125)	(2.13)	4.0363	3.7888	0.25	6.53
28	TRUE-UP	(7,617,648)	(7,617,648)	0	0.00	1,165,205,875	1,190,510,000	(25,304,125)	(2.13)	(0.6538)	(0.6399)	(0.01)	2.17
29	TOTAL JURISDICTIONAL FUEL COST	39,413,267	37,488,331	1,924,936	5.13	1,165,205,875	1,190,510,000	(25,304,125)	(2.13)	3.3825	3.1489	0.23	7.42
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.3849	3.1512	0.23	7.42
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	1,165,205,875	1,190,510,000	(25,304,125)	(2.13)	0.0046	0.0045	0.00	2.22
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.3895	3.1557	0.23	7.41
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.390	3.156		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: JULY 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 39,111,109
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	13,431
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,598,950
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	18,655,580
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	674,274
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(12,778,688)
10	Total Fuel and Net Power Transactions		$ 48,274,656

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2012
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	205,334,336	303,873,263	(98,538,927)	(32.43)	5,271,320,000	6,751,250,000	(1,479,930,000)	(21.92)	3.8953	4.5010	(0.61)	(13.46)
2	Hedging Settlement Costs (A2)	21,931,543	4,141,760	17,789,783	429.52	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	145,424	0	145,424	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	227,411,303	308,015,023	(80,603,720)	(26.17)	5,271,320,000	6,751,250,000	(1,479,930,000)	(21.92)	4.3141	4.5623	(0.25)	(5.44)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	96,442,883	42,696,000	53,746,883	125.88	6,008,938,815	1,325,843,000	4,683,095,815	353.22	1.6050	3.2203	(1.62)	(50.16)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	3,415,689	0	3,415,689	100.00	120,838,000	0	120,838,000	100.00	2.8267	0.0000	2.83	0.00
12	TOTAL COST OF PURCHASED POWER	99,858,572	42,696,000	57,162,572	133.88	6,129,776,815	1,325,843,000	4,803,933,815	362.33	1.6291	3.2203	(1.59)	(49.41)
13	Total Available MWH (Line 5 + Line 12)	327,269,875	350,711,023	(23,441,148)	(6.68)	11,401,096,815	8,077,093,000	3,324,003,815	41.15				
14	Fuel Cost of Economy Sales (A6)	(1,215,596)	(2,960,000)	1,744,404	(58.93)	(44,945,482)	(80,435,000)	35,489,518	(44.12)	(2.7046)	(3.6800)	0.98	26.51
15	Gain on Economy Sales (A6)	(393,906)	(449,000)	55,094	(12.27)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(70,795,134)	(19,863,000)	(50,932,134)	256.42	(4,579,738,539)	(558,898,000)	(4,020,840,539)	719.42	(1.5458)	(3.5540)	2.01	56.51
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(72,404,636)	(23,272,000)	(49,132,636)	211.12	(4,624,684,021)	(639,333,000)	(3,985,351,021)	623.36	(1.5656)	(3.6400)	2.07	56.99
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	254,865,239	327,439,023	(72,573,784)	(22.16)	6,776,412,794	7,437,760,000	(661,347,206)	(8.89)	3.7611	4.4024	(0.64)	(14.57)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	430,113	565,400	(135,287)	(23.93)	11,435,818	12,843,000	(1,407,182)	(10.96)	3.7611	4.4024	(0.64)	(14.57)
22	T & D Losses *	13,617,496	18,217,880	(4,600,384)	(25.25)	362,061,528	413,817,000	(51,755,472)	(12.51)	3.7611	4.4024	(0.64)	(14.57)
23	TERRITORIAL KWH SALES	254,865,238	327,439,023	(72,573,785)	(22.16)	6,402,915,448	7,011,100,000	(608,184,552)	(8.67)	3.9805	4.6703	(0.69)	(14.77)
24	Wholesale KWH Sales	7,719,229	10,707,770	(2,988,541)	(27.91)	193,902,877	228,518,000	(34,615,123)	(15.15)	3.9810	4.6857	(0.70)	(15.04)
25	Jurisdictional KWH Sales	247,146,009	316,731,253	(69,585,244)	(21.97)	6,209,012,571	6,782,582,000	(573,569,429)	(8.46)	3.9804	4.6698	(0.69)	(14.76)
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	247,446,067	316,988,996	(69,542,929)	(21.94)	6,209,012,571	6,782,582,000	(573,569,429)	(8.46)	3.9853	4.6736	(0.69)	(14.73)
28	TRUE-UP	(11,575,602)	(11,575,602)	0	0.00	6,209,012,571	6,782,582,000	(573,569,429)	(8.46)	(0.1864)	(0.1707)	(0.02)	9.20
29	TOTAL JURISDICTIONAL FUEL COST	235,870,465	305,413,394	(69,542,929)	(22.77)	6,209,012,571	6,782,582,000	(573,569,429)	(8.46)	3.7989	4.5029	(0.70)	(15.63)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.8016	4.5061	(0.70)	(15.63)
32	GPIF Reward / (Penalty)	376,551	376,551	0	0.00	6,209,012,571	6,782,582,000	(573,569,429)	(8.46)	0.0061	0.0056	0.00	8.93
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.8077	4.5117	(0.70)	(15.60)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.808	4.512		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$	*DIFFERENCE*			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	38,881,297.08	33,502,267	5,379,030.08	16.06	203,624,482.08	302,602,096	(98,977,614.00)	(32.71)
1a	Other Generation	229,811.77	184,827	44,984.77	24.34	1,709,853.77	1,271,167	438,686.77	34.51
2	Fuel Cost of Power Sold	(12,778,688.05)	(5,854,000)	(6,924,688.05)	(118.29)	(72,404,635.52)	(23,272,000)	(49,132,635.52)	(211.12)
3	Fuel Cost - Purchased Power	18,655,580.12	14,440,000	4,215,580.12	29.19	96,442,882.30	42,696,000	53,746,882.30	125.88
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	674,273.91	0	674,273.91	100.00	3,415,688.97	0	3,415,688.97	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	2,598,950.00	4,141,760	(1,542,810.00)	(37.25)	21,931,543.00	4,141,760	17,789,783.00	429.52
6	Total Fuel & Net Power Transactions	48,261,224.83	46,414,854	1,846,370.83	3.98	254,719,814.60	327,439,023	(72,719,208.48)	(22.21)
7	AdjustmentsTo Fuel Cost*	13,430.68	0	13,430.68	100.00	145,423.79	0	145,423.79	100.00
8	Adj. Total Fuel & Net Power Transactions	48,274,655.51	46,414,854	1,859,801.51	4.01	254,865,238.39	327,439,023	(72,573,784.69)	(22.16)
B.	*KWH Sales*								
1	Jurisdictional Sales	1,165,205,875	1,190,510,000	(25,304,125)	(2.13)	6,209,012,571	6,782,582,000	(573,569,429)	(8.46)
2	Non-Jurisdictional Sales	32,608,586	36,383,000	(3,774,414)	(10.37)	193,902,877	228,518,000	(34,615,123)	(15.15)
3	Total Territorial Sales	1,197,814,461	1,226,893,000	(29,078,539)	(2.37)	6,402,915,448	7,011,100,000	(608,184,552)	(8.67)
4	Juris. Sales as % of Total Terr. Sales	97.2777	97.0345	0.2432	0.25	96.9716	96.7406	0.2310	0.24

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	42,471,643.13	43,394,090	(922,446.37)	(2.13)	274,846,997.03	307,268,773	(32,421,776.16)	(10.55)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	7,617,648.00	7,617,648	0.00	0.00	11,575,600.76	11,575,601	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(376,277.16)	(376,277)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	50,035,537.25	50,957,984	(922,446.75)	(1.81)	286,046,320.63	318,468,097	(32,421,776.37)	(10.18)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	48,274,655.51	46,414,854	1,859,801.51	4.01	254,865,238.39	327,439,023	(72,573,784.61)	(22.16)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2777	97.0345	0.2432	0.25	96.9716	96.7406	0.2310	0.24
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	47,030,915.27	45,105,979	1,924,936.27	4.27	247,446,065.92	316,988,996	(69,542,930.08)	(21.94)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,004,621.98	5,852,005	(2,847,383.02)	48.66	38,600,254.71	1,479,101	37,121,153.71	(2,509.71)
8	Interest Provision for the Month	4,907.92	(2,659)	7,566.92	284.58	20,275.70	(9,871)	30,146.70	305.41
9	Beginning True-Up & Interest Provision	41,569,856.45	(20,389,254)	61,959,110.45	303.88	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(7,617,648.00)	(7,617,648)	0.00	0.00	(11,575,600.76)	(11,575,601)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	36,961,738.35	(22,157,556)	59,119,294.35	266.81	36,973,623.34	(22,157,556)	59,131,179.34	266.87
12	Adjustment*	0.00	0	0.00	0.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	36,961,738.35	(22,157,556)	59,119,294.35	266.81	36,961,738.35	(22,157,556)	59,119,294.35	266.81

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

		CURRENT MONTH			
			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	41,569,856.45	(20,389,254)	61,959,110.45	(303.88)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	36,956,830.43	(22,154,897)	59,111,727.43	(266.81)
3	Total of Beginning & Ending True-Up Amts.	78,526,686.88	(42,544,151)	121,070,837.88	(284.58)
4	Average True-Up Amount	39,263,343.44	(21,272,076)	60,535,419.44	(284.58)
5	Interest Rate 1st Day of Reporting Business Month	0.15	0.15	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.15	0.15	0.0000	
7	Total (D5+D6)	0.30	0.30	0.0000	
8	Annual Average Interest Rate	0.15	0.15	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0125	0.0125	0.0000	
10	Interest Provision (D4*D9)	4,907.92	(2,659)	7,566.92	(284.58)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	136,164	68,474	67,690	98.86	974,709	400,086	574,623	143.62
2	COAL	26,866,792	23,960,303	2,906,489	12.13	137,086,630	231,063,490	(93,976,860)	(40.67)
3	GAS	11,951,328	9,600,211	2,351,117	24.49	64,047,178	72,010,522	(7,963,344)	(11.06)
4	GAS (B.L.)	52,966	0	52,966	100.00	2,648,001	-	2,648,001	100.00
5	LANDFILL GAS	63,431	58,106	5,325	9.16	433,665	399,166	34,499	8.64
6	OIL - C.T.	40,428	0	40,428	100.00	144,153	0	144,153	100.00
7	TOTAL ($)	39,111,109	33,687,094	5,424,015	16.10	205,334,336	303,873,263	(98,538,927)	(32.43)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	519,955	488,249	31,706	6.49	2,663,659	4,676,266	(2,012,607)	(43.04)
10	GAS	373,167	379,707	(6,540)	(1.72)	2,592,127	2,059,596	532,531	25.86
11	LANDFILL GAS	2,156	2,240	(84)	(3.75)	15,070	15,388	(318)	(2.07)
12	OIL - C.T.	107	0	107	100.00	464	0	464	100.00
13	TOTAL (MWH)	895,385	870,196	25,189	2.89	5,271,320	6,751,250	(1,479,930)	(21.92)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,083	572	511	89.34	7,711	3,019	4,692	155.40
15	COAL (TONS)	258,516	232,856	25,660	11.02	1,258,084	2,198,999	(940,915)	(42.79)
16	GAS (MCF) (1)	2,871,148	2,620,111	251,037	9.58	19,242,757	14,289,297	4,953,460	34.67
17	OIL - C.T. (BBL)	386	0	386	100.00	1,401	0	1,401	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,733,215	6,680,800	(947,585)	(14.18)	30,494,208	52,020,156	(21,525,948)	(41.38)
19	GAS - Generation (1)	2,900,853	2,698,715	202,138	7.49	18,481,196	14,717,974	3,763,222	25.57
20	OIL - C.T.	2,243	0	2,243	100.00	8,141	0	8,141	100.00
21	TOTAL (MMBTU)	8,636,311	9,379,515	(743,204)	(7.92)	48,983,545	66,738,130	(17,754,585)	(26.60)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	58.07	56.11	1.96	3.49	50.53	69.26	(18.73)	(27.04)
24	GAS	41.68	43.63	(1.95)	(4.47)	49.17	30.51	18.66	61.16
25	LANDFILL GAS	0.24	0.26	(0.02)	(7.69)	0.29	0.23	0.06	26.09
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	125.73	119.71	6.02	5.03	126.41	132.51	(6.10)	(4.60)
29	COAL ($/TON)	103.93	102.90	1.03	1.00	108.96	105.08	3.88	3.69
30	GAS ($/MCF) (1)	4.10	3.57	0.53	14.85	3.38	4.95	(1.57)	(31.72)
31	OIL - C.T. ($/BBL)	104.74	0.00	104.74	100.00	102.89	0.00	102.89	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.72	3.60	1.12	31.11	4.61	4.45	0.16	3.60
33	GAS - Generation (1)	4.04	3.47	0.57	16.43	3.37	4.80	(1.43)	(29.79)
34	OIL - C.T.	18.02	0.00	18.02	100.00	17.71	0.00	17.71	100.00
35	TOTAL ($/MMBTU)	4.49	3.56	0.93	26.12	4.15	4.53	(0.38)	(8.39)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,026	13,683	(2,657)	(19.42)	11,448	11,124	324	2.91
37	GAS - Generation (1)	7,917	7,216	701	9.71	7,277	7,245	32	0.44
38	OIL - C.T.	20,963	0	20,963	100.00	17,545	0	17,545	100.00
39	TOTAL (BTU/KWH)	9,742	10,878	(1,136)	(10.44)	9,413	9,949	(536)	(5.39)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.20	4.92	0.28	5.69	5.28	4.95	0.33	6.67
41	GAS	3.20	2.53	0.67	26.48	2.47	3.50	(1.03)	(29.43)
42	LANDFILL GAS	2.94	2.59	0.35	13.51	2.88	2.59	0.29	11.20
43	OIL - C.T.	37.78	0.00	37.78	100.00	31.07	0.00	31.07	100.00
44	TOTAL (¢/KWH)	4.37	3.87	0.50	12.92	3.90	4.50	(0.60)	(13.33)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(1,546)	(2.8)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,016	0	0	0.00	0.00
3									Gas-S	0	1,016	0	0		0.00
4									Oil-S	0	139,041	0	0		0.00
5	Crist 5		75	24,594	55.2	100.0	63.6	11,612	Coal	12,319	11,591	285,575	1,331,065	5.41	108.05
6				6,198					Gas-G	70,934	1,016	72,069	235,146	3.79	3.31
7									Gas-S	0	1,016	0	0		0.00
8									Oil-S	71	139,041	416	8,136		114.59
9	Crist 6		291	55,943	25.8	100.0	70.4	10,514	Coal	25,114	11,710	588,170	2,713,601	4.85	108.05
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	15,978	1,016	16,233	52,966		3.31
12									Oil-S	0	139,041	0	0		0.00
13	Crist 7		465	145,892	55.0	91.3	58.6	11,424	Coal	71,838	11,600	1,666,652	7,762,238	5.32	108.05
14				44,269					Gas-G	498,353	1,016	506,327	1,652,036	3.73	3.31
15									Gas-S	0	1,016	0	0		0.00
16									Oil-S	9	139,041	54	1,064		118.22
17	Scholz 1		46	3,075	9.0	99.9	42.0	14,281	Coal	1,915	11,464	43,914	166,499	5.41	86.94
18									Oil-S	9	138,460	52	1,123		124.78
19	Scholz 2		46	2,902	8.5	100.0	38.5	14,416	Coal	1,832	11,415	41,834	159,295	5.49	86.95
20									Oil-S	13	138,460	78	1,699		130.69
21	Smith 1		162	57,983	48.1	95.5	50.4	10,765	Coal	27,064	11,532	624,195	3,202,267	5.52	118.32
22									Oil-S	239	137,405	1,377	30,483		127.54
23	Smith 2		195	55,339	38.1	99.8	41.0	11,148	Coal	26,854	11,486	616,897	3,177,502	5.74	118.33
24									Oil-S	397	137,405	2,289	50,686		127.67
25	Smith 3		556	315,931	76.4	92.8	89.9	7,351	Gas-G	2,285,883	1,016	2,322,457	9,834,334	3.11	4.30
26	Smith A	(2)	32	107	0.4	99.9	79.3	20,963	Oil	386	138,370	2,243	40,428	37.78	104.74
27	Other Generation			6,769									229,812	3.40	0.00
28	Perdido			2,156					Landfill Gas				63,431	2.94	0.00
29	Daniel 1	(1)	255	130,008	68.5	100.0	68.5	10,274	Coal	66,559	10,034	1,335,723	6,467,972	4.98	97.18
30									Oil-S	121	138,214	702	15,082		124.64
31	Daniel 2	(1)	255	45,765	24.1	100.0	44.5	11,095	Coal	25,021	10,147	507,756	2,431,423	5.31	97.18
32									Oil-S	224	138,214	1,298	27,892		124.52
33	Total		2,453	895,385	49.1	96.4	62.7	9,742				8,636,311	39,656,180	4.43	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	118,173	
N/A	Crist Coal Adjustment	(658,368)	
N/A	Smith Coal Adjustment	(817)	
	Recoverable Fuel	39,111,109	4.37

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	1,234	3,488	(2,254)	(64.62)	8,563	10,844	(2,281)	(21.03)
3	UNIT COST ($/BBL)	125.15	118.05	7.10	6.01	126.72	129.67	(2.95)	(2.28)
4	AMOUNT ($)	154,438	411,746	(257,308)	(62.49)	1,085,130	1,406,114	(320,984)	(22.83)
5	*BURNED:*								
6	UNITS (BBL)	1,154	572	582	101.75	8,006	3,020	4,986	165.10
7	UNIT COST ($/BBL)	125.80	119.71	6.09	5.09	126.61	132.48	(5.87)	(4.43)
8	AMOUNT ($)	145,173	68,474	76,699	112.01	1,013,676	400,086	613,590	153.36
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,945	8,781	(2,836)	(32.30)	5,945	8,781	(2,836)	(32.30)
11	UNIT COST ($/BBL)	119.53	118.96	0.57	0.48	119.53	118.96	0.57	0.48
12	AMOUNT ($)	710,610	1,044,617	(334,007)	(31.97)	710,610	1,044,617	(334,007)	(31.97)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	183,502	205,500	(21,998)	(10.70)	1,221,471	1,896,042	(674,571)	(35.58)
16	UNIT COST ($/TON)	93.19	113.76	(20.57)	(18.08)	109.47	107.65	1.82	1.69
17	AMOUNT ($)	17,101,118	23,378,012	(6,276,894)	(26.85)	133,716,165	204,104,156	(70,387,991)	(34.49)
18	*BURNED:*								
19	UNITS (TONS)	258,516	232,856	25,660	11.02	1,258,084	2,198,999	(940,915)	(42.79)
20	UNIT COST ($/TON)	103.49	102.90	0.59	0.57	108.29	105.08	3.21	3.05
21	AMOUNT ($)	26,752,678	23,960,303	2,792,375	11.65	136,243,667	231,063,489	(94,819,822)	(41.04)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	864,734	912,392	(47,658)	(5.22)	864,734	912,392	(47,658)	(5.22)
24	UNIT COST ($/TON)	106.04	110.44	(4.40)	(3.98)	106.04	110.44	(4.40)	(3.98)
25	AMOUNT ($)	91,696,339	100,765,608	(9,069,269)	(9.00)	91,696,339	100,765,608	(9,069,269)	(9.00)
26	DAYS SUPPLY	41	43	(2)	(4.65)	42	44	(2)	(4.55)
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,918,916	2,698,715	220,201	8.16	19,428,403	14,717,974	4,710,429	32.00
29	UNIT COST ($/MMBTU)	4.17	3.49	0.68	19.48	3.35	4.89	(1.54)	(31.49)
30	AMOUNT ($)	12,173,336	9,415,384	2,757,952	29.29	65,089,700	72,028,809	(6,939,109)	(9.63)
31	*BURNED:*								
32	UNITS (MMBTU)	2,917,086	2,698,715	218,371	8.09	19,522,252	14,717,974	4,804,278	32.64
33	UNIT COST ($/MMBTU)	4.04	3.49	0.55	15.76	3.33	4.89	(1.56)	(31.90)
34	AMOUNT ($)	11,774,482	9,415,384	2,359,098	25.06	64,985,324	72,028,809	(7,043,485)	(9.78)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	935,729	0	935,729	100.00	935,729	0	935,729	100.00
37	UNIT COST ($/MMBTU)	4.23	0.00	4.23	100.00	4.23	0.00	4.23	100.00
38	AMOUNT ($)	3,962,300	0	3,962,300	100.00	3,962,300	0	3,962,300	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	354	536	(182)	(33.96)	1,064	536	528	98.51
41	UNIT COST ($/BBL)	124.89	118.36	6.53	5.52	134.50	118.36	16.00	13.52
42	AMOUNT ($)	44,212	63,439	(19,227)	(30.31)	143,111	63,439	79,672	125.59
43	*BURNED:*								
44	UNITS (BBL)	386	0	386	100.00	1,401	0	1,401	100.00
45	UNIT COST ($/BBL)	104.74	0.00	104.74	100.00	102.89	0.00	102.89	100.00
46	AMOUNT ($)	40,428	0	40,428	100.00	144,153	0	144,153	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,490	7,058	(568)	(8.05)	6,490	7,058	(568)	(8.05)
49	UNIT COST ($/BBL)	104.98	104.99	(0.01)	(0.01)	104.98	104.99	(0.01)	(0.01)
50	AMOUNT ($)	681,352	741,007	(59,655)	(8.05)	681,352	741,007	(59,655)	(8.05)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

	(1) SOLD TO	(2) TYPE AND SCHEDULE	CURRENT MONTH (3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) (5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(8) (5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		172,303,000	0	172,303,000	3.27	3.68	5,629,000	6,339,000
2	Various	Economy Sales	4,477,000	0	4,477,000	3.44	3.82	154,000	171,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	71,000	71,000
4	TOTAL ESTIMATED SALES		176,780,000	0	176,780,000	3.31	3.72	5,854,000	6,581,000
	ACTUAL								
5	Southern Company Interchange		381,252,184	0	381,252,184	3.33	3.58	12,714,538	13,658,869
6	A.E.C.	External	119,915	0	119,915	3.71	4.70	4,446	5,639
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	23,592	0	23,592	3.26	4.10	768	967
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	2	0
13	CARGILE	External	173,858	0	173,858	3.50	6.59	6,087	11,460
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	15,533	0	15,533	3.53	4.11	548	638
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	294,153	0	294,153	2.80	5.46	8,240	16,063
19	EAGLE EN	External	43,937	0	43,937	3.53	4.66	1,551	2,047
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	2,036,868	0	2,036,868	4.06	7.41	82,693	150,841
23	FPC	External	37,369	0	37,369	4.34	5.68	1,621	2,124
24	FPL	External	259,960	0	259,960	3.92	5.43	10,191	14,104
25	JARON	External	202,847	0	202,847	3.53	5.40	7,155	10,954
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	46,146	0	46,146	3.43	4.79	1,582	2,211
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	146,304	0	146,304	3.32	4.48	4,851	6,548
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	3,900	0	3,900	3.52	4.30	137	168
34	NRG	External	1,430	0	1,430	3.37	3.40	48	49
35	OPC	External	37,371	0	37,371	4.16	5.36	1,554	2,002
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	548,341	0	548,341	2.84	4.47	15,581	24,529
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	618,729	0	618,729	3.90	5.89	24,101	36,471
40	SEC	External	3,900	0	3,900	2.04	2.72	80	106
41	SEPA	External	210,186	0	210,186	3.12	4.45	6,554	9,362
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	1,305,070	0	1,305,070	3.65	5.01	47,614	65,397
44	TEA	External	428,577	0	428,577	3.23	5.10	13,839	21,852
45	TECO	External	585	0	585	3.68	3.84	22	22
46	TENASKA	External	0	0	0	0.00	0.00	0	0
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	204,139	0	204,139	3.80	5.50	7,751	11,228
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	0	0	0	0.00	0.00	0	0
51	Less: Flow-Thru Energy		(6,782,208)	0	(6,782,208)	3.65	3.65	(247,658)	(247,658)
52	SEPA		964,126	964,126	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	64,150	64,150
54	Other transactions including adj.		300,204,120	208,953,560	91,250,560	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		682,420,430	209,917,686	472,502,744	1.87	2.02	12,778,688	13,806,478
56	Difference in Amount		505,640,430	209,917,686	295,722,744	(1.44)	(1.70)	6,924,688	7,225,478
57	Difference in Percent		286.03	0.00	167.28	(43.50)	(45.70)	118.29	109.79

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
						PERIOD TO DATE			
				KWH		(a)	(b)		
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		558,898,000	0	558,898,000	3.55	3.91	19,863,000	21,879,000
2	Various	Economy Sales	80,435,000	0	80,435,000	3.68	4.10	2,960,000	3,299,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	449,000	71,000
4	TOTAL ESTIMATED SALES		639,333,000	0	639,333,000	3.64	3.95	23,272,000	25,249,000
	ACTUAL								
5	Southern Company Interchange		2,917,040,734	0	2,917,040,734	2.47	2.70	72,006,572	78,724,617
6	A.E.C.	External	1,138,998	0	1,138,998	2.99	3.82	34,088	43,548
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	6,304	0	6,304	3.40	5.50	214	347
9	AMERENEM	External	23,592	0	23,592	3.26	4.10	768	967
10	ARCLIGHT	External	17,550	0	17,550	3.68	4.99	647	876
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	231,384	0	231,384	2.84	3.85	6,577	8,907
13	CARGILE	External	1,852,237	0	1,852,237	2.32	3.34	42,969	61,903
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	403,090	0	403,090	2.10	3.07	8,464	12,376
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	2,961,872	0	2,961,872	2.02	2.93	59,961	86,906
19	EAGLE EN	External	498,898	0	498,898	2.58	3.65	12,861	18,189
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	39,969	0	39,969	2.06	3.88	823	1,551
22	ENTERGY	External	13,521,315	0	13,521,315	3.36	6.93	454,160	937,273
23	FPC	External	508,486	0	508,486	3.43	5.24	17,435	26,657
24	FPL	External	2,819,966	0	2,819,966	2.58	3.87	72,856	109,148
25	JARON	External	228,847	0	228,847	3.31	5.04	7,586	11,525
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	486,687	0	486,687	2.92	3.89	14,211	18,928
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	775,718	0	775,718	2.31	3.26	17,920	25,310
32	NCEMC	External	12,674	0	12,674	1.90	2.80	241	355
33	NCMPA1	External	282,871	0	282,871	2.48	2.95	7,010	8,353
34	NRG	External	4,680	0	4,680	2.24	3.12	105	146
35	OPC	External	407,893	0	407,893	2.40	3.48	9,775	14,196
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	7,473,902	0	7,473,902	2.01	3.06	150,187	228,452
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	2,346,033	0	2,346,033	3.29	4.85	77,209	113,810
40	SEC	External	627,325	0	627,325	2.23	2.92	13,975	18,292
41	SEPA	External	524,363	0	524,363	2.63	3.75	13,765	19,684
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	1,881,295	0	1,881,295	3.40	4.65	63,880	87,555
44	TEA	External	4,447,106	0	4,447,106	2.10	3.09	93,598	137,264
45	TECO	External	268,490	0	268,490	2.35	3.72	6,298	9,977
46	TENASKA	External	27,622	0	27,622	3.15	4.29	871	1,186
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	823,052	0	823,052	2.57	3.88	21,125	31,939
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	109,847	0	109,847	2.33	3.23	2,563	3,546
51	Less: Flow-Thru Energy		(44,750,241)	0	(44,750,241)	2.71	2.71	(1,211,438)	(1,211,438)
52	SEPA		8,409,014	8,409,014	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	393,906	393,906
54	Other transactions including adj.		1,699,039,032	1,257,534,600	441,504,432	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		4,624,684,021	1,265,943,614	3,358,740,407	1.57	1.72	72,404,636	79,556,809
56	Difference in Amount		3,985,351,021	1,265,943,614	2,719,407,407	(2.07)	(2.23)	49,132,636	54,307,809
57	Difference in Percent		623.36	0.00	425.35	(56.87)	(56.46)	211.12	215.09

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JULY 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

CURRENT MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	19,507,000	0	0	0	3.44	3.44	670,670
6 International Paper	COG 1	102,000	0	0	0	3.53	3.53	3,604
7 TOTAL		19,609,000	0	0	0	3.44	3.44	674,274

PERIOD-TO-DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	17
5 Ascend Performance Materials	COG 1	115,873,000	0	0	0	2.66	2.66	3,078,188
6 International Paper	COG 1	739,000	0	0	0	2.76	2.76	20,412
7 TOTAL		120,838,000	0	0	0	2.83	2.83	3,415,689

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2012

	(1) PURCHASED FROM	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	36,513,000	3.85	1,407,000	678,952,000	4.00	27,155,000
2	Economy Energy	3,126,000	3.93	123,000	32,968,000	4.14	1,366,000
3	Other Purchases	589,780,000	2.19	12,910,000	613,923,000	2.31	14,175,000
4	TOTAL ESTIMATED PURCHASES	629,419,000	2.29	14,440,000	1,325,843,000	3.22	42,696,000
	ACTUAL						
5	Southern Company Interchange	52,981,984	3.92	2,074,974	481,485,703	2.78	13,396,068
6	Non-Associated Companies	17,386,179	2.76	479,969	128,896,809	2.85	3,672,039
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	652,489,000	2.50	16,335,054	3,710,757,000	2.17	80,489,380
9	Other Wheeled Energy	121,600,000	0.00	N/A	620,296,000	0.00	N/A
10	Other Transactions	186,605,269	0.02	34,569	1,112,253,544	0.02	220,769
11	Less: Flow-Thru Energy	(6,782,208)	3.97	(268,986)	(44,750,241)	2.98	(1,335,373)
12	TOTAL ACTUAL PURCHASES	1,024,280,224	1.82	18,655,580	6,008,938,815	1.60	96,442,883
13	Difference in Amount	394,861,224	(0.47)	4,215,580	4,683,095,815	(1.62)	53,746,883
14	Difference in Percent	62.73	(20.52)	29.19	353.22	(50.31)	125.88

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692	0	0	1,227,653
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ 1,484,274**		**$ 2,071,953**		**$ 7,640,423**	**$ 17,059,646**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	0	0											1,227,653
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	8,266,469											24,128,402
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(5,502)											(35,442)
SUBTOTAL					$ 8,260,967		$ -		$ -		$ -		$ -		$ -	$ 24,092,960
TOTAL					$ 8,260,967		$ -		$ -		$ -		$ -		$ -	$ 25,320,613

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

AUGUST 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2012
CURRENT MONTH

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	38,826,153	35,384,903	3,441,250	9.73	856,214,000	897,412,000	(41,198,000)	(4.59)	4.5346	3.9430	0.59	15.00
2	Hedging Settlement Costs (A2)	2,886,418	4,014,600	(1,128,182)	(28.10)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	6,121	0	6,121	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	41,718,692	39,399,503	2,319,189	5.89	856,214,000	897,412,000	(41,198,000)	(4.59)	4.8725	4.3903	0.48	10.98
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	17,597,294	14,130,000	3,467,294	24.54	915,483,004	623,100,000	292,383,004	46.92	1.9222	2.2677	(0.35)	(15.24)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	591,136	0	591,136	100.00	18,211,000	0	18,211,000	100.00	3.2460	0.0000	3.25	0.00
12	TOTAL COST OF PURCHASED POWER	18,188,430	14,130,000	4,058,430	28.72	933,694,004	623,100,000	310,594,004	49.85	1.9480	2.2677	(0.32)	(14.10)
13	Total Available MWH (Line 5 + Line 12)	59,907,122	53,529,503	6,377,619	11.91	1,789,908,004	1,520,512,000	269,396,004	17.72				
14	Fuel Cost of Economy Sales (A6)	(111,101)	(190,000)	78,899	(41.53)	(3,280,956)	(5,941,000)	2,660,044	(44.77)	(3.3862)	(3.1981)	(0.19)	(5.88)
15	Gain on Economy Sales (A6)	(1,321)	(68,000)	66,679	(98.06)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(11,041,043)	(7,361,000)	(3,680,043)	49.99	(602,426,272)	(243,384,000)	(359,042,272)	147.52	(1.8328)	(3.0244)	1.19	39.40
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(11,153,465)	(7,619,000)	(3,534,465)	46.39	(605,707,228)	(249,325,000)	(356,382,228)	142.94	(1.8414)	(3.0559)	1.21	39.74
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	48,753,657	45,910,503	2,843,154	6.19	1,184,200,776	1,271,187,000	(86,986,224)	(6.84)	4.1170	3.6116	0.51	13.99
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	72,971	75,807	(2,836)	(3.74)	1,772,443	2,099,000	(326,557)	(15.56)	4.1170	3.6116	0.51	13.99
22	T & D Losses *	2,584,365	3,109,949	(525,584)	(16.90)	62,773,017	86,110,000	(23,336,983)	(27.10)	4.1170	3.6116	0.51	13.99
23	TERRITORIAL KWH SALES	48,753,657	45,910,503	2,843,154	6.19	1,119,655,316	1,182,978,000	(63,322,684)	(5.35)	4.3543	3.8809	0.47	12.20
24	Wholesale KWH Sales	1,343,651	1,422,767	(79,116)	(5.56)	30,857,455	36,660,000	(5,802,545)	(15.83)	4.3544	3.8810	0.47	12.20
25	Jurisdictional KWH Sales	47,410,006	44,487,736	2,922,270	6.57	1,088,797,861	1,146,318,000	(57,520,139)	(5.02)	4.3543	3.8809	0.47	12.20
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	47,481,121	44,554,468	2,926,653	6.57	1,088,797,861	1,146,318,000	(57,520,139)	(5.02)	4.3609	3.8867	0.47	12.20
28	TRUE-UP	(7,617,648)	(7,617,648)	0	0.00	1,088,797,861	1,146,318,000	(57,520,139)	(5.02)	(0.6996)	(0.6645)	(0.04)	5.28
29	TOTAL JURISDICTIONAL FUEL COST	39,863,473	36,936,820	2,926,653	7.92	1,088,797,861	1,146,318,000	(57,520,139)	(5.02)	3.6613	3.2222	0.44	13.63
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.6639	3.2245	0.44	13.63
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	1,088,797,861	1,146,318,000	(57,520,139)	(5.02)	0.0049	0.0047	0.00	4.26
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.6688	3.2292	0.44	13.61
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.669	3.229		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: AUGUST 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 38,826,153
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	6,121
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,886,418
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	17,597,294
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	591,136
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(11,153,465)
10	Total Fuel and Net Power Transactions		$ 48,753,657

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	244,160,489	339,258,166	(95,097,677)	(28.03)	6,127,534,000	7,648,662,000	(1,521,128,000)	(19.89)	3.9846	4.4355	(0.45)	(10.17)
2	Hedging Settlement Costs (A2)	24,817,961	8,156,360	16,661,601	204.28	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	151,545	0	151,545	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	269,129,995	347,414,526	(78,284,531)	(22.53)	6,127,534,000	7,648,662,000	(1,521,128,000)	(19.89)	4.3921	4.5422	(0.15)	(3.30)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	114,040,177	56,826,000	57,214,177	100.68	6,924,421,819	1,948,943,000	4,975,478,819	255.29	1.6469	2.9157	(1.27)	(43.52)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	4,006,825	0	4,006,825	100.00	139,049,000	0	139,049,000	100.00	2.8816	0.0000	2.88	0.00
12	TOTAL COST OF PURCHASED POWER	118,047,002	56,826,000	61,221,002	107.73	7,063,470,819	1,948,943,000	5,114,527,819	262.43	1.6712	2.9157	(1.24)	(42.68)
13	Total Available MWH (Line 5 + Line 12)	387,176,997	404,240,526	(17,063,529)	(4.22)	13,191,004,819	9,597,605,000	3,593,399,819	37.44				
14	Fuel Cost of Economy Sales (A6)	(1,326,697)	(3,150,000)	1,823,303	(57.88)	(48,226,438)	(86,376,000)	38,149,562	(44.17)	(2.7510)	(3.6468)	0.90	24.56
15	Gain on Economy Sales (A6)	(395,228)	(517,000)	121,772	(23.55)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(81,836,177)	(27,224,000)	(54,612,177)	200.60	(5,182,164,811)	(802,282,000)	(4,379,882,811)	545.93	(1.5792)	(3.3933)	1.81	53.46
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(83,558,102)	(30,891,000)	(52,667,102)	170.49	(5,230,391,249)	(888,658,000)	(4,341,733,249)	488.57	(1.5975)	(3.4761)	1.88	54.04
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	303,618,895	373,349,526	(69,730,631)	(18.68)	7,960,613,570	8,708,947,000	(748,333,430)	(8.59)	3.8140	4.2870	(0.47)	(11.03)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	503,763	640,564	(136,801)	(21.36)	13,208,261	14,942,000	(1,733,739)	(11.60)	3.8140	4.2870	(0.47)	(11.03)
22	T & D Losses *	16,203,190	21,431,870	(5,228,680)	(24.40)	424,834,545	499,927,000	(75,092,455)	(15.02)	3.8140	4.2870	(0.47)	(11.03)
23	TERRITORIAL KWH SALES	303,618,895	373,349,526	(69,730,631)	(18.68)	7,522,570,764	8,194,078,000	(671,507,236)	(8.20)	4.0361	4.5563	(0.52)	(11.42)
24	Wholesale KWH Sales	9,062,880	12,130,537	(3,067,657)	(25.29)	224,760,332	265,178,000	(40,417,668)	(15.24)	4.0322	4.5745	(0.54)	(11.85)
25	Jurisdictional KWH Sales	294,556,015	361,218,989	(66,662,974)	(18.46)	7,297,810,432	7,928,900,000	(631,089,568)	(7.96)	4.0362	4.5557	(0.52)	(11.40)
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	294,927,188	361,543,464	(66,616,276)	(18.43)	7,297,810,432	7,928,900,000	(631,089,568)	(7.96)	4.0413	4.5598	(0.52)	(11.37)
28	TRUE-UP	(19,193,250)	(19,193,250)	0	0.00	7,297,810,432	7,928,900,000	(631,089,568)	(7.96)	(0.2630)	(0.2421)	(0.02)	8.63
29	TOTAL JURISDICTIONAL FUEL COST	275,733,938	342,350,214	(66,616,276)	(19.46)	7,297,810,432	7,928,900,000	(631,089,568)	(7.96)	3.7783	4.3177	(0.54)	(12.49)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.7810	4.3208	(0.54)	(12.49)
32	GPIF Reward / (Penalty)	430,344	430,344	0	0.00	7,297,810,432	7,928,900,000	(631,089,568)	(7.96)	0.0059	0.0054	0.00	9.26
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.7869	4.3262	(0.54)	(12.47)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.787	4.326		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	38,606,225.20	35,200,140	3,406,085.20	9.68	242,230,707.28	337,802,236	(95,571,528.80)	(28.29)
1a	Other Generation	219,928.46	184,763	35,165.46	19.03	1,929,782.23	1,455,930	473,852.23	32.55
2	Fuel Cost of Power Sold	(11,153,465.22)	(7,619,000)	(3,534,465.22)	(46.39)	(83,558,100.74)	(30,891,000)	(52,667,100.74)	(170.49)
3	Fuel Cost - Purchased Power	17,597,294.29	14,130,000	3,467,294.29	24.54	114,040,176.59	56,826,000	57,214,176.59	100.68
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	591,135.87	0	591,135.87	100.00	4,006,824.84	0	4,006,824.84	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	2,886,418.00	4,014,600	(1,128,182.00)	(28.10)	24,817,961.00	8,156,360	16,661,601.00	204.28
6	Total Fuel & Net Power Transactions	48,747,536.60	45,910,503	2,837,033.60	6.18	303,467,351.20	373,349,526	(69,882,174.88)	(18.72)
7	AdjustmentsTo Fuel Cost*	6,120.50	0	6,120.50	100.00	151,544.29	0	151,544.29	100.00
8	Adj. Total Fuel & Net Power Transactions	48,753,657.10	45,910,503	2,843,154.10	6.19	303,618,895.49	373,349,526	(69,730,630.59)	(18.68)
B.	*KWH Sales*								
1	Jurisdictional Sales	1,088,797,861	1,146,318,000	(57,520,139)	(5.02)	7,297,810,432	7,928,900,000	(631,089,568)	(7.96)
2	Non-Jurisdictional Sales	30,857,455	36,660,000	(5,802,545)	(15.83)	224,760,332	265,178,000	(40,417,668)	(15.24)
3	Total Territorial Sales	1,119,655,316	1,182,978,000	(63,322,684)	(5.35)	7,522,570,764	8,194,078,000	(671,507,236)	(8.20)
4	Juris. Sales as % of Total Terr. Sales	97.2440	96.9010	0.3430	0.35	97.0122	96.7638	0.2484	0.26

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	39,690,694.02	41,783,291	(2,092,597.08)	(5.01)	314,537,691.05	349,052,064	(34,514,373.24)	(9.89)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	7,617,648.00	7,617,648	0.00	0.00	19,193,248.76	19,193,249	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(430,031.04)	(430,031)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	47,254,588.14	49,347,185	(2,092,596.86)	(4.24)	333,300,908.77	367,815,282	(34,514,373.23)	(9.38)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	48,753,657.10	45,910,503	2,843,154.10	6.19	303,618,895.49	373,349,526	(69,730,630.51)	(18.68)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2440	96.9010	0.3430	0.35	97.0122	96.7638	0.2484	0.26
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	47,481,121.32	44,554,468	2,926,653.32	6.57	294,927,187.24	361,543,464	(66,616,276.76)	(18.43)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(226,533.18)	4,792,717	(5,019,250.18)	104.73	38,373,721.53	6,271,818	32,101,903.53	(511.84)
8	Interest Provision for the Month	3,865.64	(2,758)	6,623.64	240.16	24,141.34	(12,629)	36,770.34	291.16
9	Beginning True-Up & Interest Provision	36,961,738.35	(22,157,556)	59,119,294.35	266.81	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(7,617,648.00)	(7,617,648)	0.00	0.00	(19,193,248.76)	(19,193,249)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	29,121,422.81	(24,985,245)	54,106,667.81	216.55	29,133,307.80	(24,985,245)	54,118,552.80	216.60
12	Adjustment*	0.00	0	0.00	0.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	29,121,422.81	(24,985,245)	54,106,667.81	216.55	29,121,422.81	(24,985,245)	54,106,667.81	216.55

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	36,961,738.35	(22,157,556)	59,119,294.35	(266.81)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	29,117,557.17	(24,982,487)	54,100,044.17	(216.55)
3	Total of Beginning & Ending True-Up Amts.	66,079,295.52	(47,140,043)	113,219,338.52	(240.18)
4	Average True-Up Amount	33,039,647.76	(23,570,022)	56,609,669.76	(240.18)
	Interest Rate				
5	1st Day of Reporting Business Month	0.15	0.15	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.13	0.13	0.0000	
7	Total (D5+D6)	0.28	0.28	0.0000	
8	Annual Average Interest Rate	0.14	0.14	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0117	0.0117	0.0000	
10	Interest Provision (D4*D9)	3,865.64	(2,758)	6,623.64	(240.16)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	447,336	68,002	379,334	557.83	1,422,045	468,088	953,957	203.80
2	COAL	26,694,669	25,504,077	1,190,592	4.67	163,781,299	256,567,567	(92,786,268)	(36.16)
3	GAS	11,616,444	9,746,637	1,869,807	19.18	75,663,622	81,757,159	(6,093,537)	(7.45)
4	GAS (B.L.)	9,046	0	9,046	100.00	2,657,047	-	2,657,047	100.00
5	LANDFILL GAS	56,253	58,106	(1,853)	(3.19)	489,918	457,272	32,646	7.14
6	OIL - C.T.	2,405	8,081	(5,676)	(70.24)	146,558	8,081	138,477	1,713.61
7	TOTAL ($)	38,826,153	35,384,903	3,441,250	9.73	244,160,489	339,258,166	(95,097,677)	(28.03)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	485,824	515,155	(29,331)	(5.69)	3,149,483	5,191,421	(2,041,938)	(39.33)
10	GAS	368,469	379,985	(11,516)	(3.03)	2,960,596	2,439,581	521,015	21.36
11	LANDFILL GAS	1,920	2,240	(320)	(14.29)	16,990	17,628	(638)	(3.62)
12	OIL - C.T.	1	32	(31)	(96.88)	465	32	433	1,353.13
13	TOTAL (MWH)	856,214	897,412	(41,198)	(4.59)	6,127,534	7,648,662	(1,521,128)	(19.89)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	3,472	572	2,900	506.99	11,183	3,591	7,592	211.40
15	COAL (TONS)	250,583	244,510	6,073	2.48	1,508,667	2,443,509	(934,842)	(38.26)
16	GAS (MCF) (1)	2,734,339	2,622,807	111,532	4.25	21,977,096	16,912,104	5,064,992	29.95
17	OIL - C.T. (BBL)	23	77	(54)	(70.13)	1,424	77	1,347	1,749.35
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,478,479	6,982,991	(1,504,512)	(21.55)	35,972,687	59,003,147	(23,030,460)	(39.03)
19	GAS - Generation (1)	2,767,553	2,701,492	66,061	2.45	21,248,749	17,419,466	3,829,283	21.98
20	OIL - C.T.	133	450	(317)	(70.44)	8,274	450	7,824	1,738.67
21	TOTAL (MMBTU)	8,246,165	9,684,933	(1,438,768)	(14.86)	57,229,710	76,423,063	(19,193,353)	(25.11)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	56.75	57.41	(0.66)	(1.15)	51.39	67.87	(16.48)	(24.28)
24	GAS	43.03	42.34	0.69	1.63	48.32	31.90	16.42	51.47
25	LANDFILL GAS	0.22	0.25	(0.03)	(12.00)	0.28	0.23	0.05	21.74
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	128.84	118.88	9.96	8.38	127.16	130.34	(3.18)	(2.44)
29	COAL ($/TON)	106.53	104.31	2.22	2.13	108.56	105.00	3.56	3.39
30	GAS ($/MCF) (1)	4.17	3.63	0.54	14.88	3.48	4.74	(1.26)	(26.58)
31	OIL - C.T. ($/BBL)	104.57	104.95	(0.38)	(0.36)	102.92	104.95	(2.03)	(1.93)
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.96	3.66	1.30	35.52	4.67	4.36	0.31	7.11
33	GAS - Generation (1)	4.12	3.52	0.60	17.05	3.47	4.60	(1.13)	(24.57)
34	OIL - C.T.	18.08	17.96	0.12	0.67	17.71	17.96	(0.25)	(1.39)
35	TOTAL ($/MMBTU)	4.67	3.62	1.05	29.01	4.22	4.41	(0.19)	(4.31)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,277	13,555	(2,278)	(16.81)	11,422	11,366	56	0.49
37	GAS - Generation (1)	7,650	7,218	432	5.99	0	7,241	(7,241)	(100.00)
38	OIL - C.T.	133,000	14,063	118,937	845.74	17,794	14,063	3,731	26.53
39	TOTAL (BTU/KWH)	9,729	10,889	(1,160)	(10.65)	(1,077)	10,059	(11,136)	(110.71)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.59	4.96	0.63	12.70	5.33	4.95	0.38	7.68
41	GAS	3.15	2.57	0.58	22.57	2.56	3.35	(0.79)	(23.58)
42	LANDFILL GAS	2.93	2.59	0.34	13.13	2.88	2.59	0.29	11.20
43	OIL - C.T.	240.50	25.25	215.25	852.48	31.52	25.25	6.27	24.83
44	TOTAL (¢/KWH)	4.53	3.94	0.59	14.97	3.98	4.44	(0.46)	(10.36)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(872)	(1.6)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	0	0	0	0.00	0.00
3									Gas-S	0	0	0	0		0.00
4									Oil-S	0	139,041	0	2		0.00
5	Crist 5		75	31,036	56.0	99.5	66.4	11,151	Coal	14,910	11,605	346,069	1,580,734	5.09	106.02
6				206					Gas-G	2,255	0	2,286	7,583	3.68	3.36
7									Gas-S	0	0	0	0		0.00
8									Oil-S	219	139,041	1,280	25,035		114.32
9	Crist 6		291	77,128	35.8	96.9	69.1	11,782	Coal	39,454	11,516	908,699	4,182,732	5.42	106.02
10				419					Gas-G	4,905	0	4,974	16,496	3.94	3.36
11									Gas-S	2,690	0	2,728	9,046		3.36
12									Oil-S	0	139,041	0	0		0.00
13	Crist 7		465	151,825	54.2	99.6	57.9	10,909	Coal	70,943	11,673	1,656,235	7,521,099	4.95	106.02
14				35,845					Gas-G	385,717	0	391,117	1,297,220	3.62	3.36
15									Gas-S	0	0	0	0		0.00
16									Oil-S	103	139,041	602	11,762		114.19
17	Scholz 1		46	(270)	(0.8)	100.0	0.0	0	Coal	13	0	0	1,110	0.00	85.38
18									Oil-S	5	137,647	28	631		126.20
19	Scholz 2		46	(179)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	52,462	43.5	99.2	43.7	11,023	Coal	24,670	11,721	578,311	2,867,485	5.47	116.23
22									Oil-S	575	140,028	3,383	78,572		136.65
23	Smith 2		195	51,886	35.8	94.5	36.0	11,412	Coal	25,324	11,691	592,118	2,943,479	5.67	116.23
24									Oil-S	470	140,028	2,766	64,246		136.69
25	Smith 3		556	325,282	78.6	98.3	92.1	7,283	Gas-G	2,338,772	1,013	2,369,176	10,075,217	3.10	4.31
26	Smith A	(2)	32	1	0.0	100.0	7.8	133,000	Oil	23	138,041	133	2,405	240.50	104.57
27	Other Generation			6,717									219,928	3.27	0.00
28	Perdido			1,920					Landfill Gas				56,253	2.93	0.00
29	Daniel 1	(1)	255	63,387	33.4	98.6	39.6	11,148	Coal	38,545	9,166	706,622	3,800,920	6.00	98.61
30									Oil-S	1,047	139,369	6,129	133,200		127.22
31	Daniel 2	(1)	255	59,421	31.3	97.8	39.2	11,231	Coal	36,725	9,086	667,350	3,621,400	6.09	98.61
32									Oil-S	1,052	139,369	6,160	133,890		127.27
33	Total		2,453	856,214	46.9	98.3	56.1	9,729				8,246,166	38,650,446	4.51	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	179,767	
	Recoverable Fuel	38,826,154	4.53

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,191	1,444	(253)	(17.52)	9,754	12,288	(2,534)	(20.62)
3	UNIT COST ($/BBL)	142.98	118.12	24.86	21.05	128.71	128.31	0.40	0.31
4	AMOUNT ($)	170,289	170,561	(272)	(0.16)	1,255,419	1,576,675	(321,256)	(20.38)
5	*BURNED :*								
6	UNITS (BBL)	3,523	572	2,951	515.91	11,529	3,592	7,937	220.96
7	UNIT COST ($/BBL)	128.90	118.88	10.02	8.43	127.31	130.31	(3.00)	(2.30)
8	AMOUNT ($)	454,122	68,002	386,120	567.81	1,467,798	468,088	999,710	213.57
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	3,613	9,653	(6,040)	(62.57)	3,613	9,653	(6,040)	(62.57)
11	UNIT COST ($/BBL)	118.12	118.84	(0.72)	(0.61)	118.12	118.84	(0.72)	(0.61)
12	AMOUNT ($)	426,777	1,147,176	(720,399)	(62.80)	426,777	1,147,176	(720,399)	(62.80)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	163,677	203,224	(39,547)	(19.46)	1,385,148	2,099,266	(714,118)	(34.02)
16	UNIT COST ($/TON)	103.50	114.24	(10.74)	(9.40)	108.77	108.29	0.48	0.44
17	AMOUNT ($)	16,940,314	23,215,669	(6,275,355)	(27.03)	150,656,479	227,319,825	(76,663,346)	(33.72)
18	*BURNED :*								
19	UNITS (TONS)	250,583	244,510	6,073	2.48	1,508,667	2,443,509	(934,842)	(38.26)
20	UNIT COST ($/TON)	105.83	104.31	1.52	1.46	107.89	105.00	2.89	2.75
21	AMOUNT ($)	26,518,960	25,504,077	1,014,883	3.98	162,762,627	256,567,566	(93,804,939)	(36.56)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	777,828	871,106	(93,278)	(10.71)	777,828	871,106	(93,278)	(10.71)
24	UNIT COST ($/TON)	105.57	113.05	(7.48)	(6.62)	105.57	113.05	(7.48)	(6.62)
25	AMOUNT ($)	82,117,692	98,477,200	(16,359,508)	(16.61)	82,117,692	98,477,200	(16,359,508)	(16.61)
26	DAYS SUPPLY	37	41	(4)	(9.76)	38	42	(4)	(9.52)
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,687,480	2,701,492	(14,012)	(0.52)	22,115,883	17,419,466	4,696,417	26.96
29	UNIT COST ($/MMBTU)	4.12	3.54	0.58	16.38	3.44	4.68	(1.24)	(26.50)
30	AMOUNT ($)	11,070,446	9,561,874	1,508,572	15.78	76,160,146	81,590,683	(5,430,537)	(6.66)
31	*BURNED :*								
32	UNITS (MMBTU)	2,770,281	2,701,492	68,789	2.55	22,292,533	17,419,466	4,873,067	27.97
33	UNIT COST ($/MMBTU)	4.12	3.54	0.58	16.38	3.43	4.68	(1.25)	(26.71)
34	AMOUNT ($)	11,405,563	9,561,874	1,843,689	19.28	76,390,887	81,590,683	(5,199,796)	(6.37)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	852,928	0	852,928	100.00	852,928	0	852,928	100.00
37	UNIT COST ($/MMBTU)	4.25	0.00	4.25	100.00	4.25	0.00	4.25	100.00
38	AMOUNT ($)	3,627,183	0	3,627,183	100.00	3,627,183	0	3,627,183	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	77	(77)	(100.00)	1,064	613	451	73.57
41	UNIT COST ($/BBL)	0.00	118.08	(118.08)	(100.00)	134.50	118.32	16.00	13.52
42	AMOUNT ($)	0	9,092	(9,092)	(100.00)	143,111	72,531	70,580	97.31
43	*BURNED :*								
44	UNITS (BBL)	23	77	(54)	(70.13)	1,424	77	1,347	1,749.35
45	UNIT COST ($/BBL)	104.57	104.95	(0.38)	(0.36)	102.92	104.95	(2.03)	(1.93)
46	AMOUNT ($)	2,405	8,081	(5,676)	(70.24)	146,558	8,081	138,477	1,713.61
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,467	7,058	(591)	(8.37)	6,467	7,058	(591)	(8.37)
49	UNIT COST ($/BBL)	104.99	104.99	0.00	0.00	104.99	104.99	0.00	0.00
50	AMOUNT ($)	678,947	741,007	(62,060)	(8.38)	678,947	741,007	(62,060)	(8.38)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢/KWH FUEL COST	¢/KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		243,384,000	0	243,384,000	3.02	3.47	7,361,000	8,456,000
2	Various	Economy Sales	5,941,000	0	5,941,000	3.20	3.64	190,000	216,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	68,000	68,000
4	TOTAL ESTIMATED SALES		249,325,000	0	249,325,000	3.06	3.51	7,619,000	8,740,000
	ACTUAL								
5	Southern Company Interchange		374,979,056	0	374,979,056	2.97	3.22	11,151,835	12,058,809
6	A.E.C.	External	692,170	0	692,170	3.25	3.83	22,525	26,522
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	(768)	0
10	ARCLIGHT	External	5,135	0	5,135	18.26	4.70	937	241
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	103,984	0	103,984	3.36	4.30	3,496	4,472
13	CARGILE	External	9,359	0	9,359	1.60	2.60	150	243
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	0	0	0	0.00	0.00	0	0
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	58,494	0	58,494	3.83	8.00	2,241	4,679
19	EAGLE EN	External	20,538	0	20,538	3.46	4.30	710	883
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	97,490	0	97,490	4.26	7.50	4,153	7,312
23	FPC	External	0	0	0	0.00	0.00	0	0
24	FPL	External	537,598	0	537,598	3.60	5.11	19,362	27,497
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	39,320	0	39,320	3.29	4.32	1,295	1,700
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	48,356	0	48,356	2.71	3.41	1,313	1,651
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	0	0	0	0.00	0.00	3	0
34	NRG	External	11,374	0	11,374	4.53	5.90	515	671
35	OPC	External	29,247	0	29,247	3.13	3.93	915	1,150
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	21,708	0	21,708	2.91	2.81	632	611
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	71,489	0	71,489	3.71	4.41	2,653	3,150
40	SEC	External	17,613	0	17,613	3.34	4.28	589	754
41	SEPA	External	945,582	0	945,582	3.31	4.35	31,312	41,106
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	87,750	0	87,750	4.22	5.03	3,704	4,416
44	TEA	External	390,676	0	390,676	3.03	3.97	11,837	15,498
45	TECO	External	0	0	0	0.00	0.00	(1)	0
46	TENASKA	External	0	0	0	0.00	0.00	0	0
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	58,623	0	58,623	3.70	4.42	2,170	2,592
49	UPP	External	0	0	0	0.00	0.00	0	0
50	WRI	External	34,450	0	34,450	3.94	5.83	1,358	2,008
51	Less: Flow-Thru Energy		(3,268,997)	0	(3,268,997)	3.39	3.39	(110,792)	(110,792)
52	SEPA		1,193,544	1,193,544	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	1,321	1,321
54	Other transactions including adj.		229,522,669	183,095,594	46,427,075	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		605,707,228	184,289,138	421,418,090	1.84	2.00	11,153,465	12,095,175
56	Difference in Amount		356,382,228	184,289,138	172,093,090	(1.22)	(1.51)	3,534,465	3,355,175
57	Difference in Percent		142.94	0.00	69.02	(39.87)	(43.02)	46.39	38.39

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		802,282,000	0	802,282,000	3.39	3.78	27,224,000	30,335,000
2	Various	Economy Sales	86,376,000	0	86,376,000	3.65	4.07	3,150,000	3,515,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	517,000	139,000
4	TOTAL ESTIMATED SALES		888,658,000	0	888,658,000	3.48	3.82	30,891,000	33,989,000
	ACTUAL								
5	Southern Company Interchange		3,292,019,790	0	3,292,019,790	2.53	2.76	83,158,407	90,783,426
6	A.E.C.	External	1,831,168	0	1,831,168	3.09	3.83	56,612	70,071
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	6,304	0	6,304	3.40	5.50	214	347
9	AMERENEM	External	23,592	0	23,592	0.00	4.10	0	967
10	ARCLIGHT	External	22,685	0	22,685	6.98	4.92	1,584	1,117
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	335,368	0	335,368	3.00	3.99	10,074	13,379
13	CARGILE	External	1,861,596	0	1,861,596	2.32	3.34	43,119	62,146
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	403,090	0	403,090	2.10	3.07	8,465	12,376
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	3,020,366	0	3,020,366	2.06	3.03	62,202	91,585
19	EAGLE EN	External	519,436	0	519,436	2.61	3.67	13,571	19,072
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	39,969	0	39,969	2.06	3.88	823	1,551
22	ENTERGY	External	13,618,805	0	13,618,805	3.37	6.94	458,313	944,585
23	FPC	External	508,486	0	508,486	3.43	5.24	17,435	26,657
24	FPL	External	3,357,564	0	3,357,564	2.75	4.07	92,218	136,645
25	JARON	External	228,847	0	228,847	3.31	5.04	7,586	11,525
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	526,007	0	526,007	2.95	3.92	15,506	20,628
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	824,074	0	824,074	2.33	3.27	19,233	26,961
32	NCEMC	External	12,674	0	12,674	1.90	2.80	241	355
33	NCMPA1	External	282,871	0	282,871	2.48	2.95	7,014	8,353
34	NRG	External	16,054	0	16,054	3.86	5.09	620	817
35	OPC	External	437,140	0	437,140	2.45	3.51	10,691	15,346
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	7,495,610	0	7,495,610	2.01	3.06	150,819	229,063
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	2,417,522	0	2,417,522	3.30	4.84	79,862	116,960
40	SEC	External	644,938	0	644,938	2.26	2.95	14,564	19,046
41	SEPA	External	1,469,945	0	1,469,945	3.07	4.14	45,077	60,791
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	1,969,045	0	1,969,045	3.43	4.67	67,584	91,971
44	TEA	External	4,837,782	0	4,837,782	2.18	3.16	105,435	152,762
45	TECO	External	268,490	0	268,490	2.35	3.72	6,297	9,977
46	TENASKA	External	27,622	0	27,622	3.15	4.29	871	1,186
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	881,675	0	881,675	2.64	3.92	23,295	34,531
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	144,297	0	144,297	2.72	3.85	3,921	5,554
51	Less: Flow-Thru Energy		(48,019,238)	0	(48,019,238)	2.75	2.75	(1,322,230)	(1,322,230)
52	SEPA		9,602,558	9,602,558	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	395,227	395,227
54	Other transactions including adj.		1,928,561,701	1,440,630,194	487,931,507	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		5,230,391,249	1,450,232,752	3,780,158,497	1.60	1.75	83,558,101	91,651,984
56	Difference in Amount		4,341,733,249	1,450,232,752	2,891,500,497	(1.88)	(2.07)	52,667,101	57,662,984
57	Difference in Percent		488.57	0.00	325.38	(54.02)	(54.19)	170.49	169.65

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: AUGUST 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

CURRENT MONTH

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	35
5	Ascend Performance Materials	COG 1	18,160,000	0	0	0	3.25	3.25	589,292
6	International Paper	COG 1	51,000	0	0	0	3.55	3.55	1,809
7	TOTAL		18,211,000	0	0	0	3.25	3.25	591,136

PERIOD-TO-DATE

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	52
5	Ascend Performance Materials	COG 1	134,033,000	0	0	0	2.74	2.74	3,667,480
6	International Paper	COG 1	790,000	0	0	0	2.81	2.81	22,221
7	TOTAL		139,049,000	0	0	0	2.88	2.88	4,006,825

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	11,614,000	4.12	479,000	690,566,000	4.00	27,634,000
2	Economy Energy	4,144,000	3.76	156,000	37,112,000	4.10	1,522,000
3	Other Purchases	607,342,000	2.22	13,495,000	1,221,265,000	2.27	27,670,000
4	TOTAL ESTIMATED PURCHASES	623,100,000	2.27	14,130,000	1,948,943,000	2.92	56,826,000
	ACTUAL						
5	Southern Company Interchange	30,697,618	2.13	654,053	512,183,321	2.74	14,050,121
6	Non-Associated Companies	70,897,652	(9.78)	(6,933,429)	199,794,461	(1.63)	(3,261,390)
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	626,922,000	3.83	23,990,133	4,337,679,000	2.41	104,479,513
9	Other Wheeled Energy	75,449,000	0.00	N/A	695,745,000	0.00	N/A
10	Other Transactions	114,785,731	0.01	6,186	1,227,039,275	0.02	226,955
11	Less: Flow-Thru Energy	(3,268,997)	3.66	(119,649)	(48,019,238)	3.03	(1,455,022)
12	TOTAL ACTUAL PURCHASES	915,483,004	1.92	17,597,294	6,924,421,819	1.65	114,040,177
13	Difference in Amount	292,383,004	(0.35)	3,467,294	4,975,478,819	(1.27)	57,214,177
14	Difference in Percent	46.92	(15.42)	24.54	255.29	(43.49)	100.68

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692	0	0	1,227,653
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ 1,484,274**		**$ 2,071,953**		**$ 7,640,423**	**$ 17,059,646**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

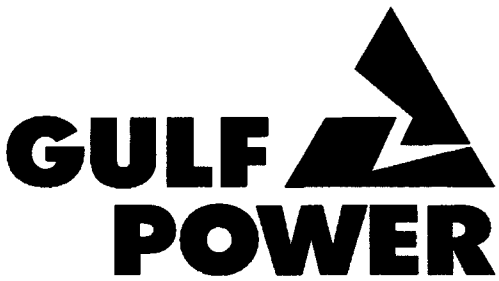
	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	0	0	0	0									1,227,653
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	8,266,469	Varies	7,144,861									31,273,263
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(5,502)	Varies	(8,163)									(43,605)
SUBTOTAL					$ 8,260,967		$ 7,136,698	$	-	$	-	$	-	$	-	$ 31,229,658
TOTAL					**$ 8,260,967**		**$ 7,136,698**	$	-	$	-	$	-	$	-	$ 32,457,311

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

SEPTEMBER 2012



A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2012
CURRENT MONTH

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	21,327,016	28,869,106	(7,542,090)	(26.13)	551,322,000	754,091,000	(202,769,000)	(26.89)	3.8683	3.8283	0.04	1.04
2	Hedging Settlement Costs (A2)	2,922,638	3,542,830	(620,192)	(17.51)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	3,643	0	3,643	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	24,253,297	32,411,936	(8,158,639)	(25.17)	551,322,000	754,091,000	(202,769,000)	(26.89)	4.3991	4.2981	0.10	2.35
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	16,699,512	14,561,000	2,138,512	14.69	876,783,345	581,806,000	294,977,345	50.70	1.9046	2.5027	(0.60)	(23.90)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	488,150	0	488,150	100.00	17,510,000	0	17,510,000	100.00	2.7878	0.0000	2.79	0.00
12	TOTAL COST OF PURCHASED POWER	17,187,662	14,561,000	2,626,662	18.04	894,293,345	581,806,000	312,487,345	53.71	1.9219	2.5027	(0.58)	(23.21)
13	Total Available MWH (Line 5 + Line 12)	41,440,959	46,972,936	(5,531,977)	(11.78)	1,445,615,345	1,335,897,000	109,718,345	8.21				
14	Fuel Cost of Economy Sales (A6)	(252,061)	(149,000)	(103,061)	69.17	(9,311,118)	(4,410,000)	(4,901,118)	111.14	(2.7071)	(3.3787)	0.67	19.88
15	Gain on Economy Sales (A6)	(27,114)	(43,000)	15,886	(36.94)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(3,848,061)	(5,119,000)	1,270,939	(24.83)	(370,738,791)	(181,561,000)	(189,177,791)	104.20	(1.0379)	(2.8194)	1.78	63.19
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(4,127,236)	(5,311,000)	1,183,764	(22.29)	(380,049,909)	(185,971,000)	(194,078,909)	104.36	(1.0860)	(2.8558)	1.77	61.97
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	37,313,723	41,661,936	(4,348,213)	(10.44)	1,065,565,436	1,149,926,000	(84,360,564)	(7.34)	3.5018	3.6230	(0.12)	(3.35)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	63,174	66,917	(3,743)	(5.59)	1,804,040	1,847,000	(42,960)	(2.33)	3.5018	3.6230	(0.12)	(3.35)
22	T & D Losses *	1,912,613	2,543,056	(630,443)	(24.79)	54,617,996	70,192,000	(15,574,004)	(22.19)	3.5018	3.6230	(0.12)	(3.35)
23	TERRITORIAL KWH SALES	37,313,723	41,661,936	(4,348,213)	(10.44)	1,009,143,400	1,077,887,000	(68,743,600)	(6.38)	3.6976	3.8651	(0.17)	(4.33)
24	Wholesale KWH Sales	1,009,262	1,260,649	(251,387)	(19.94)	27,295,395	32,616,000	(5,320,605)	(16.31)	3.6976	3.8651	(0.17)	(4.33)
25	Jurisdictional KWH Sales	36,304,461	40,401,287	(4,096,826)	(10.14)	981,848,005	1,045,271,000	(63,422,995)	(6.07)	3.6976	3.8651	(0.17)	(4.33)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	36,358,918	40,461,889	(4,102,971)	(10.14)	981,848,005	1,045,271,000	(63,422,995)	(6.07)	3.7031	3.8709	(0.17)	(4.33)
28	TRUE-UP	(7,617,648)	(7,617,648)	0	0.00	981,848,005	1,045,271,000	(63,422,995)	(6.07)	(0.7758)	(0.7288)	(0.05)	6.45
29	TOTAL JURISDICTIONAL FUEL COST	28,741,270	32,844,241	(4,102,971)	(12.49)	981,848,005	1,045,271,000	(63,422,995)	(6.07)	2.9273	3.1421	(0.21)	(6.84)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									2.9294	3.1444	(0.22)	(6.84)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	981,848,005	1,045,271,000	(63,422,995)	(6.07)	0.0055	0.0051	0.00	7.84
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.9349	3.1495	(0.21)	(6.81)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.935	3.150		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: SEPTEMBER 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 21,327,016
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	3,643
4	Hedging Settlement Costs	Schedule A-2, Line A-5	2,922,638
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	16,699,512
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	488,150
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(4,127,236)
10	Total Fuel and Net Power Transactions		$ 37,313,723

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2012
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	265,487,506	368,127,272	(102,639,766)	(27.88)	6,678,856,000	8,402,753,000	(1,723,897,000)	(20.52)	3.9750	4.3810	(0.41)	(9.27)
2	Hedging Settlement Costs (A2)	27,740,599	11,699,190	16,041,409	137.12	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	155,188	0	155,188	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	293,383,293	379,826,462	(86,443,169)	(22.76)	6,678,856,000	8,402,753,000	(1,723,897,000)	(20.52)	4.3927	4.5203	(0.13)	(2.82)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	130,739,689	71,387,000	59,352,689	83.14	7,801,205,164	2,530,749,000	5,270,456,164	208.26	1.6759	2.8208	(1.14)	(40.59)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	4,494,975	0	4,494,975	100.00	156,559,000	0	156,559,000	100.00	2.8711	0.0000	2.87	0.00
12	TOTAL COST OF PURCHASED POWER	135,234,664	71,387,000	63,847,664	89.44	7,957,764,164	2,530,749,000	5,427,015,164	214.44	1.6994	2.8208	(1.12)	(39.75)
13	Total Available MWH (Line 5 + Line 12)	428,617,957	451,213,462	(22,595,505)	(5.01)	14,636,620,164	10,933,502,000	3,703,118,164	33.87				
14	Fuel Cost of Economy Sales (A6)	(1,578,758)	(3,299,000)	1,720,242	(52.14)	(57,537,556)	(90,786,000)	33,248,444	(36.62)	(2.7439)	(3.6338)	0.89	24.49
15	Gain on Economy Sales (A6)	(422,342)	(560,000)	137,658	(24.58)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(85,684,238)	(32,343,000)	(53,341,238)	164.92	(5,552,903,602)	(983,843,000)	(4,569,060,602)	464.41	(1.5431)	(3.2874)	1.74	53.06
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(87,685,338)	(36,202,000)	(51,483,338)	142.21	(5,610,441,158)	(1,074,629,000)	(4,535,812,158)	422.08	(1.5629)	(3.3688)	1.81	53.61
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	340,932,619	415,011,462	(74,078,843)	(17.85)	9,026,179,006	9,858,873,000	(832,693,994)	(8.45)	3.7772	4.2095	(0.43)	(10.27)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	567,045	706,733	(139,688)	(19.77)	15,012,301	16,789,000	(1,776,699)	(10.58)	3.7772	4.2095	(0.43)	(10.27)
22	T & D Losses *	18,109,881	23,999,159	(5,889,278)	(24.54)	479,452,541	570,119,000	(90,666,459)	(15.90)	3.7772	4.2095	(0.43)	(10.27)
23	TERRITORIAL KWH SALES	340,932,618	415,011,462	(74,078,844)	(17.85)	8,531,714,164	9,271,965,000	(740,250,836)	(7.98)	3.9961	4.4760	(0.48)	(10.72)
24	Wholesale KWH Sales	10,072,142	13,391,186	(3,319,044)	(24.79)	252,055,727	297,794,000	(45,738,273)	(15.36)	3.9960	4.4968	(0.50)	(11.14)
25	Jurisdictional KWH Sales	330,860,476	401,620,276	(70,759,800)	(17.62)	8,279,658,437	8,974,171,000	(694,512,563)	(7.74)	3.9961	4.4753	(0.48)	(10.71)
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	331,266,105	402,005,353	(70,719,248)	(17.59)	8,279,658,437	8,974,171,000	(694,512,563)	(7.74)	4.0012	4.4796	(0.48)	(10.68)
28	TRUE-UP	(26,810,898)	(26,810,898)	0	0.00	8,279,658,437	8,974,171,000	(694,512,563)	(7.74)	(0.3238)	(0.2988)	(0.03)	8.37
29	TOTAL JURISDICTIONAL FUEL COST	304,475,207	375,194,455	(70,719,248)	(18.85)	8,279,658,437	8,974,171,000	(694,512,563)	(7.74)	3.6774	4.1808	(0.50)	(12.04)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.6800	4.1838	(0.50)	(12.04)
32	GPIF Reward / (Penalty)	484,137	484,137	0	0.00	8,279,658,437	8,974,171,000	(694,512,563)	(7.74)	0.0058	0.0054	0.00	7.41
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.6858	4.1892	(0.50)	(12.02)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.686	4.189		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	21,063,329.37	28,690,293	(7,626,963.63)	(26.58)	263,294,036.65	366,492,529	(103,198,492.43)	(28.16)
1a	Other Generation	263,687.01	178,813	84,874.01	47.47	2,193,469.24	1,634,743	558,726.24	34.18
2	Fuel Cost of Power Sold	(4,127,235.55)	(5,311,000)	1,183,764.45	22.29	(87,685,336.29)	(36,202,000)	(51,483,336.29)	(142.21)
3	Fuel Cost - Purchased Power	16,699,511.45	14,561,000	2,138,511.45	14.69	130,739,688.04	71,387,000	59,352,688.04	83.14
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	488,149.53	0	488,149.53	100.00	4,494,974.37	0	4,494,974.37	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	2,922,638.00	3,542,830	(620,192.00)	(17.51)	27,740,599.00	11,699,190	16,041,409.00	137.12
6	Total Fuel & Net Power Transactions	37,310,079.81	41,661,936	(4,351,856.19)	(10.45)	340,777,431.01	415,011,462	(74,234,031.07)	(17.89)
7	AdjustmentsTo Fuel Cost*	3,642.76	0	3,642.76	100.00	155,187.05	0	155,187.05	100.00
8	Adj. Total Fuel & Net Power Transactions	37,313,722.57	41,661,936	(4,348,213.43)	(10.44)	340,932,618.06	415,011,462	(74,078,844.02)	(17.85)
B.	*KWH Sales*								
1	Jurisdictional Sales	981,848,005	1,045,271,000	(63,422,995)	(6.07)	8,279,658,437	8,974,171,000	(694,512,563)	(7.74)
2	Non-Jurisdictional Sales	27,295,395	32,616,000	(5,320,605)	(16.31)	252,055,727	297,794,000	(45,738,273)	(15.36)
3	Total Territorial Sales	1,009,143,400	1,077,887,000	(68,743,600)	(6.38)	8,531,714,164	9,271,965,000	(740,250,836)	(7.98)
4	Juris. Sales as % of Total Terr. Sales	97.2952	96.9741	0.3211	0.33	97.0457	96.7882	0.2575	0.27

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	35,746,931.16	38,100,128	(2,353,196.79)	(6.18)	350,284,622.21	387,152,192	(36,867,570.03)	(9.52)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	7,617,648.00	7,617,648	0.00	0.00	26,810,896.76	26,810,897	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(483,784.92)	(483,785)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	43,310,825.28	45,664,022	(2,353,196.72)	(5.15)	376,611,734.05	413,479,304	(36,867,569.95)	(8.92)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	37,313,722.57	41,661,936	(4,348,213.43)	(10.44)	340,932,618.06	415,011,462	(74,078,843.94)	(17.85)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2952	96.9741	0.3211	0.33	97.0457	96.7882	0.2575	0.27
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	36,358,917.69	40,461,889	(4,102,971.31)	(10.14)	331,286,104.93	402,005,353	(70,719,248.07)	(17.59)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	6,951,907.59	5,202,133	1,749,774.59	(33.64)	45,325,629.12	11,473,951	33,851,678.12	(295.03)
8	Interest Provision for the Month	2,648.55	(2,410)	5,058.55	209.90	26,789.89	(15,039)	41,828.89	278.14
9	Beginning True-Up & Interest Provision	29,121,422.81	(24,985,245)	54,106,667.81	216.55	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(7,617,648.00)	(7,617,648)	0.00	0.00	(26,810,896.76)	(26,810,897)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	28,458,330.95	(27,403,170)	55,861,500.95	203.85	28,470,215.94	(27,403,170)	55,873,385.94	203.89
12	Adjustment*	0.00	0	0.00	0.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	28,458,330.95	(27,403,170)	55,861,500.95	203.85	28,458,330.95	(27,403,170)	55,861,500.95	203.85

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	29,121,422.81	(24,985,245)	54,106,667.81	(216.55)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	28,455,682.40	(27,400,760)	55,856,442.40	(203.85)
3	Total of Beginning & Ending True-Up Amts.	57,577,105.21	(52,386,005)	109,963,110.21	(209.91)
4	Average True-Up Amount	28,788,552.61	(26,193,003)	54,981,555.61	(209.91)
5	Interest Rate 1st Day of Reporting Business Month	0.13	0.13	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.09	0.09	0.0000	
7	Total (D5+D6)	0.22	0.22	0.0000	
8	Annual Average Interest Rate	0.11	0.11	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0092	0.0092	0.0000	
10	Interest Provision (D4*D9)	2,648.55	(2,410)	5,058.55	(209.90)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	147,239	67,788	79,451	117.21	1,569,284	535,876	1,033,408	192.84
2	COAL	11,355,294	19,229,505	(7,874,211)	(40.95)	175,136,593	275,797,072	(100,660,479)	(36.50)
3	GAS	9,644,431	9,499,423	145,008	1.53	85,308,053	91,256,582	(5,948,529)	(6.52)
4	GAS (B.L.)	118,923	0	118,923	100.00	2,775,970	-	2,775,970	100.00
5	LANDFILL GAS	59,482	56,186	3,296	5.87	549,400	513,458	35,942	7.00
6	OIL - C.T.	1,647	16,204	(14,557)	(89.84)	148,205	24,285	123,920	510.27
7	TOTAL ($)	21,327,016	28,869,106	(7,542,090)	(26.13)	265,487,505	368,127,272	(102,639,767)	(27.88)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	233,376	383,338	(149,962)	(39.12)	3,382,859	5,574,759	(2,191,900)	(39.32)
10	GAS	315,895	368,523	(52,628)	(14.28)	3,276,491	2,808,104	468,387	16.68
11	LANDFILL GAS	2,045	2,166	(121)	(5.59)	19,035	19,794	(759)	(3.83)
12	OIL - C.T.	6	64	(58)	(90.63)	471	96	375	390.63
13	TOTAL (MWH)	551,322	754,091	(202,769)	(26.89)	6,678,856	8,402,753	(1,723,897)	(20.52)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,109	572	537	93.88	12,292	4,163	8,129	195.25
15	COAL (TONS)	107,722	184,361	(76,639)	(41.57)	1,616,389	2,627,870	(1,011,481)	(38.49)
16	GAS (MCF) (1)	2,173,032	2,540,341	(367,309)	(14.46)	24,150,128	19,452,445	4,697,683	24.15
17	OIL - C.T. (BBL)	16	154	(138)	(89.61)	1,440	231	1,209	523.38
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,622,192	5,431,157	(2,808,965)	(51.72)	38,594,879	64,434,304	(25,839,425)	(40.10)
19	GAS - Generation (1)	2,200,571	2,616,551	(415,980)	(15.90)	23,449,320	20,036,017	3,413,303	17.04
20	OIL - C.T.	91	900	(809)	(89.89)	8,365	1,350	7,015	519.63
21	TOTAL (MMBTU)	4,822,854	8,048,608	(3,225,754)	(40.08)	62,052,564	84,471,671	(22,419,107)	(26.54)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	42.33	50.83	(8.50)	(16.72)	50.64	66.34	(15.70)	(23.67)
24	GAS	57.30	48.87	8.43	17.25	49.06	33.42	15.64	46.80
25	LANDFILL GAS	0.37	0.29	0.08	27.59	0.29	0.24	0.05	20.83
26	OIL - C.T.	0.00	0.01	(0.01)	(100.00)	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	132.77	118.51	14.26	12.03	127.67	128.71	(1.04)	(0.81)
29	COAL ($/TON)	105.41	104.30	1.11	1.06	108.35	104.95	3.40	3.24
30	GAS ($/MCF) (1)	4.37	3.65	0.72	19.73	3.56	4.60	(1.04)	(22.61)
31	OIL - C.T. ($/BBL)	102.94	105.22	(2.28)	(2.17)	102.92	105.13	(2.21)	(2.10)
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.43	3.55	0.88	24.79	4.65	4.29	0.36	8.39
33	GAS - Generation (1)	4.26	3.54	0.72	20.34	3.54	4.47	(0.93)	(20.81)
34	OIL - C.T.	18.10	18.00	0.10	0.56	17.72	17.99	(0.27)	(1.50)
35	TOTAL ($/MMBTU)	4.36	3.55	0.81	22.82	4.23	4.33	(0.10)	(2.31)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,236	14,168	(2,932)	(20.69)	11,409	11,558	(149)	(1.29)
37	GAS - Generation (1)	7,169	7,208	(39)	(0.54)	7,309	7,237	72	0.99
38	OIL - C.T.	15,167	14,063	1,104	7.85	17,760	14,063	3,697	26.29
39	TOTAL (BTU/KWH)	8,926	10,783	(1,857)	(17.22)	9,414	10,124	(710)	(7.01)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.98	5.03	(0.05)	(0.99)	5.31	4.96	0.35	7.06
41	GAS	3.05	2.58	0.47	18.22	2.60	3.25	(0.65)	(20.00)
42	LANDFILL GAS	2.91	2.59	0.32	12.36	2.89	2.59	0.30	11.58
43	OIL - C.T.	27.45	25.32	2.13	8.41	31.47	25.30	6.17	24.39
44	TOTAL (¢/KWH)	3.87	3.83	0.04	1.04	3.98	4.38	(0.40)	(9.13)

Note (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(1,064)	(2.0)	99.6	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,019	0	0	0.00	0.00
3									Gas-S	2,193	1,019	2,235	52,350		23.87
4									Oil-S	46	139,041	271	5,295		115.11
5	Crist 5		75	31,827	58.9	100.0	58.9	10,488	Coal	14,518	11,496	333,808	1,465,282	4.60	100.93
6				-					Gas-G	0	1,019	0	0	0.00	0.00
7									Gas-S	369	1,019	376	8,812		23.88
8									Oil-S	211	139,041	1,234	24,124		114.33
9	Crist 6		291	134,127	64.0	94.1	67.4	10,812	Coal	62,674	11,569	1,450,143	6,325,370	4.72	100.92
10				0					Gas-G	0	1,019	0	0	0.00	0.00
11									Gas-S	2,420	1,019	2,466	57,761		23.87
12									Oil-S	31	139,041	181	3,546		114.39
13	Crist 7		465	(1,646)	(0.5)	46.7	0.0	0	Coal	0	0	0	0	0.00	0.00
14				0					Gas-G	0	1,019	0	0	0.00	0.00
15									Gas-S	0	1,019	0	0		0.00
16									Oil-S	0	139,041	0	0		0.00
17	Scholz 1		46	(242)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(169)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	21,309	18.3	60.8	45.1	11,110	Coal	10,174	11,635	236,752	1,165,171	5.47	114.52
22									Oil-S	361	139,558	2,115	50,284		139.29
23	Smith 2		195	51,705	36.8	100.0	36.8	11,409	Coal	25,401	11,612	589,919	2,909,018	5.63	114.52
24									Oil-S	459	139,558	2,692	63,990		139.41
25	Smith 3		556	306,937	76.7	100.0	76.7	7,169	Gas-G	2,168,050	1,015	2,200,571	9,380,744	3.06	4.33
26	Smith A	(2)	32	6	0.0	100.0	39.8	15,167	Oil	16	137,647	91	1,647	27.45	102.94
27	Other Generation			8,958									263,687	2.94	0.00
28	Perdido			2,045					Landfill Gas				59,482	2.91	0.00
29	Daniel 1	(1)	255	(1,593)	(0.9)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	139,949	0	0		0.00
31	Daniel 2	(1)	255	(878)	(0.5)	87.5	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	139,949	0	0		0.00
33	Total		2,453	551,322	31.2	85.3	33.6	8,926				4,822,854	21,836,563	3.96	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
N/A	Crist Coal Additive	27,697	
(4,815)	Crist Flyover Adjustment	(510,456)	
(231)	Daniel Flyover Adjustment	(22,730)	
	Recoverable Fuel	21,327,016	3.87

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	3,448	1,444	2,004	138.78	13,202	13,732	(530)	(3.86)
3	UNIT COST ($/BBL)	137.70	118.12	19.58	16.58	131.06	127.24	3.82	3.00
4	AMOUNT ($)	474,790	170,561	304,229	178.37	1,730,209	1,747,236	(17,027)	(0.97)
5	*BURNED:*								
6	UNITS (BBL)	1,157	572	585	102.27	12,686	4,164	8,522	204.66
7	UNIT COST ($/BBL)	133.00	118.51	14.49	12.23	127.83	128.69	(0.86)	(0.67)
8	AMOUNT ($)	153,880	67,788	86,092	127.00	1,621,678	535,876	1,085,802	202.62
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,904	10,525	(4,621)	(43.90)	5,904	10,525	(4,621)	(43.90)
11	UNIT COST ($/BBL)	126.64	118.76	7.88	6.64	126.64	118.76	7.88	6.64
12	AMOUNT ($)	747,687	1,249,949	(502,262)	(40.18)	747,687	1,249,949	(502,262)	(40.18)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	156,477	172,600	(16,123)	(9.34)	1,541,625	2,271,866	(730,241)	(32.14)
16	UNIT COST ($/TON)	95.05	118.98	(23.93)	(20.11)	107.37	109.10	(1.73)	(1.59)
17	AMOUNT ($)	14,872,539	20,535,574	(5,663,035)	(27.58)	165,529,018	247,855,399	(82,326,381)	(33.22)
18	*BURNED:*								
19	UNITS (TONS)	107,722	184,361	(76,639)	(41.57)	1,616,389	2,627,870	(1,011,481)	(38.49)
20	UNIT COST ($/TON)	105.19	104.30	0.89	0.85	107.71	104.95	2.76	2.63
21	AMOUNT ($)	11,331,656	19,229,505	(7,897,849)	(41.07)	174,094,283	275,797,071	(101,702,788)	(36.88)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	826,582	859,345	(32,763)	(3.81)	826,582	859,345	(32,763)	(3.81)
24	UNIT COST ($/TON)	103.63	116.12	(12.49)	(10.76)	103.63	116.12	(12.49)	(10.76)
25	AMOUNT ($)	85,658,575	99,783,269	(14,124,694)	(14.16)	85,658,575	99,783,269	(14,124,694)	(14.16)
26	DAYS SUPPLY	39	41	(2)	(4.88)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,140,662	2,616,551	(475,889)	(18.19)	24,256,545	20,036,017	4,220,528	21.06
29	UNIT COST ($/MMBTU)	4.31	3.56	0.75	21.07	3.52	4.54	(1.02)	(22.47)
30	AMOUNT ($)	9,231,377	9,320,610	(89,233)	(0.96)	85,391,523	90,911,293	(5,519,770)	(6.07)
31	*BURNED:*								
32	UNITS (MMBTU)	2,205,648	2,616,551	(410,903)	(15.70)	24,498,181	20,036,017	4,462,164	22.27
33	UNIT COST ($/MMBTU)	4.31	3.56	0.75	21.07	3.51	4.54	(1.03)	(22.69)
34	AMOUNT ($)	9,499,667	9,320,610	179,057	1.92	85,890,554	90,911,293	(5,020,739)	(5.52)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	787,942	0	787,942	100.00	787,942	0	787,942	100.00
37	UNIT COST ($/MMBTU)	4.26	0.00	4.26	100.00	4.26	0.00	4.26	100.00
38	AMOUNT ($)	3,358,893	0	3,358,893	100.00	3,358,893	0	3,358,893	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	154	(154)	(100.00)	1,064	767	297	38.72
41	UNIT COST ($/BBL)	0.00	118.08	(118.08)	(100.00)	134.50	118.27	16.00	13.53
42	AMOUNT ($)	0	18,184	(18,184)	(100.00)	143,111	90,715	52,396	57.76
43	*BURNED:*								
44	UNITS (BBL)	16	154	(138)	(89.61)	1,440	231	1,209	523.38
45	UNIT COST ($/BBL)	102.94	105.22	(2.28)	(2.17)	102.92	105.13	(2.21)	(2.10)
46	AMOUNT ($)	1,647	16,204	(14,557)	(89.84)	148,205	24,285	123,920	510.27
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,451	7,058	(607)	(8.60)	6,451	7,058	(607)	(8.60)
49	UNIT COST ($/BBL)	104.99	104.99	0.00	0.00	104.99	104.99	0.00	0.00
50	AMOUNT ($)	677,300	741,007	(63,707)	(8.60)	677,300	741,007	(63,707)	(8.60)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		181,561,000	0	181,561,000	2.82	3.22	5,119,000	5,843,000
2	Various	Economy Sales	4,410,000	0	4,410,000	3.38	3.67	149,000	162,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	43,000	43,000
4	TOTAL ESTIMATED SALES		185,971,000	0	185,971,000	2.86	3.25	5,311,000	6,048,000
	ACTUAL								
5	Southern Company Interchange		156,881,967	0	156,881,967	2.61	2.80	4,097,317	4,395,075
6	A.E.C.	External	277,851	0	277,851	2.80	3.65	7,778	10,148
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	0	0
13	CARGILE	External	187,109	0	187,109	2.47	3.18	4,619	5,956
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	109,188	0	109,188	2.05	2.83	2,241	3,085
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	519,034	0	519,034	3.11	4.26	16,136	22,095
19	EAGLE EN	External	109,255	0	109,255	2.65	3.65	2,894	3,993
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	1,301,675	0	1,301,675	3.27	5.25	42,616	68,279
23	FPC	External	6,499	0	6,499	2.85	3.30	185	214
24	FPL	External	711,586	0	711,586	2.99	3.88	21,278	27,578
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	51,998	0	51,998	3.17	3.89	1,649	2,025
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	157,931	0	157,931	2.94	4.02	4,648	6,354
32	NCEMC	External	1,300	0	1,300	2.43	3.10	32	40
33	NCMPA1	External	0	0	0	0.00	0.00	0	0
34	NRG	External	59,012	0	59,012	3.63	5.01	2,143	2,959
35	OPC	External	183,604	0	183,604	2.95	4.09	5,416	7,505
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	919,319	0	919,319	2.71	3.90	24,937	35,826
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	1,027,419	0	1,027,419	3.02	4.06	31,040	41,679
40	SEC	External	185,425	0	185,425	2.36	2.85	4,381	5,290
41	SEPA	External	2,158,053	0	2,158,053	2.14	2.48	46,236	53,583
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	39,000	0	39,000	2.98	4.47	1,162	1,742
44	TEA	External	1,146,498	0	1,146,498	2.45	3.34	28,116	38,289
45	TECO	External	143,504	0	143,504	2.86	4.07	4,110	5,843
46	TENASKA	External	3,120	0	3,120	2.76	5.00	86	156
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	12,738	0	12,738	2.80	3.90	357	497
49	UPP	External	0	0	0	0.00	0.00	0	0
50	WRI	External	0	0	0	0.00	0.00	0	0
51	Less: Flow-Thru Energy		(9,216,554)	0	(9,216,554)	2.70	2.70	(249,256)	(249,256)
52	SEPA		927,344	927,344	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	27,114	27,114
54	Other transactions including adj.		222,146,034	174,716,159	47,429,875	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		380,049,909	175,643,503	204,406,406	1.09	1.18	4,127,236	4,488,956
56	Difference in Amount		194,078,909	175,643,503	18,435,406	(1.77)	(2.07)	(1,183,764)	(1,559,044)
57	Difference in Percent		104.36	0.00	9.91	(61.89)	(63.69)	(22.29)	(25.78)

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) FUEL COST ¢/KWH	(6) (b) TOTAL COST ¢/KWH	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		983,843,000	0	983,843,000	3.29	3.68	32,343,000	36,178,000
2	Various	Economy Sales	90,786,000	0	90,786,000	3.63	4.05	3,299,000	3,677,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	560,000	182,000
4	TOTAL ESTIMATED SALES		1,074,629,000	0	1,074,629,000	3.37	3.73	36,202,000	40,037,000
	ACTUAL								
5	Southern Company Interchange		3,448,901,757	0	3,448,901,757	2.53	2.76	87,255,724	95,178,501
6	A.E.C.	External	2,109,019	0	2,109,019	3.05	3.80	64,390	80,219
7	AECI	External	24,310	0	24,310	2.06	3.28	502	797
8	AEP	External	6,304	0	6,304	3.40	5.50	214	347
9	AMERENEM	External	23,592	0	23,592	0.00	4.10	0	967
10	ARCLIGHT	External	22,685	0	22,685	6.98	4.92	1,584	1,117
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	335,368	0	335,368	3.00	3.99	10,074	13,379
13	CARGILE	External	2,048,705	0	2,048,705	2.33	3.32	47,738	68,102
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	512,278	0	512,278	2.09	3.02	10,706	15,461
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	3,539,400	0	3,539,400	2.21	3.21	78,337	113,680
19	EAGLE EN	External	628,691	0	628,691	2.62	3.67	16,465	23,065
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	39,969	0	39,969	2.06	3.88	823	1,551
22	ENTERGY	External	14,920,480	0	14,920,480	3.36	6.79	500,930	1,012,864
23	FPC	External	514,985	0	514,985	3.42	5.22	17,621	26,871
24	FPL	External	4,069,150	0	4,069,150	2.79	4.04	113,496	164,223
25	JARON	External	228,847	0	228,847	3.31	5.04	7,586	11,525
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	578,005	0	578,005	2.97	3.92	17,155	22,653
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	982,005	0	982,005	2.43	3.39	23,881	33,315
32	NCEMC	External	13,974	0	13,974	1.95	2.83	272	395
33	NCMPA1	External	282,871	0	282,871	2.48	2.95	7,014	8,353
34	NRG	External	75,066	0	75,066	3.68	5.03	2,763	3,776
35	OPC	External	620,744	0	620,744	2.59	3.68	16,106	22,851
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	8,414,929	0	8,414,929	2.09	3.15	175,756	264,888
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	3,444,941	0	3,444,941	3.22	4.60	110,902	158,639
40	SEC	External	830,363	0	830,363	2.28	2.93	18,945	24,336
41	SEPA	External	3,627,998	0	3,627,998	2.52	3.15	91,313	114,373
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	2,008,045	0	2,008,045	3.42	4.67	68,746	93,713
44	TEA	External	5,984,280	0	5,984,280	2.23	3.19	133,551	191,051
45	TECO	External	411,994	0	411,994	2.53	3.84	10,407	15,820
46	TENASKA	External	30,742	0	30,742	3.11	4.37	957	1,342
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	894,413	0	894,413	2.64	3.92	23,652	35,027
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	144,297	0	144,297	2.72	3.85	3,921	5,554
51	Less: Flow-Thru Energy		(57,235,792)	0	(57,235,792)	2.75	2.75	(1,571,486)	(1,571,486)
52	SEPA		10,529,902	10,529,902	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	422,341	422,341
54	Other transactions including adj.		2,150,707,735	1,615,346,353	535,361,382	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		5,610,441,158	1,625,876,255	3,984,564,903	1.56	1.71	87,685,337	96,140,940
56	Difference in Amount		4,535,812,158	1,625,876,255	2,909,935,903	(1.81)	(2.02)	51,483,337	56,103,940
57	Difference in Percent		422.08	0.00	270.79	(53.71)	(54.16)	142.21	140.13

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: SEPTEMBER 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

CURRENT MONTH

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5	Ascend Performance Materials	COG 1	17,399,000	0	0	0	2.79	2.79	485,114
6	International Paper	COG 1	111,000	0	0	0	2.73	2.73	3,035
7	TOTAL		17,510,000	0	0	0	2.79	2.79	488,150

PERIOD-TO-DATE

	(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3	Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	52
5	Ascend Performance Materials	COG 1	151,432,000	0	0	0	2.74	2.74	4,152,594
6	International Paper	COG 1	901,000	0	0	0	2.80	2.80	25,257
7	TOTAL		156,559,000	0	0	0	2.87	2.87	4,494,974

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2012

	(1) PURCHASED FROM	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	33,032,000	3.62	1,195,000	723,598,000	3.98	28,829,000
2	Economy Energy	3,127,000	3.81	119,000	40,239,000	4.08	1,641,000
3	Other Purchases	545,647,000	2.43	13,247,000	1,766,912,000	2.32	40,917,000
4	TOTAL ESTIMATED PURCHASES	581,806,000	2.50	14,561,000	2,530,749,000	2.82	71,387,000
	ACTUAL						
5	Southern Company Interchange	100,050,585	2.50	2,505,128	612,233,906	2.70	16,555,249
6	Non-Associated Companies	54,054,047	0.64	347,018	253,848,508	(1.15)	(2,914,372)
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	557,877,000	2.53	14,092,955	4,895,556,000	2.42	118,572,468
9	Other Wheeled Energy	70,456,000	0.00	N/A	766,201,000	0.00	N/A
10	Other Transactions	103,562,267	0.03	26,545	1,330,601,542	0.02	253,500
11	Less: Flow-Thru Energy	(9,216,554)	2.95	(272,134)	(57,235,792)	3.02	(1,727,156)
12	TOTAL ACTUAL PURCHASES	876,783,345	1.90	16,699,512	7,801,205,164	1.68	130,739,689
13	Difference in Amount	294,977,345	(0.60)	2,138,512	5,270,456,164	(1.14)	59,352,689
14	Difference in Percent	50.70	(24.00)	14.69	208.26	(40.43)	83.14

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 156 of 209

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692	0	0	1,227,653
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ 1,484,274**		**$ 2,071,953**		**$ 7,640,423**	**$ 17,059,646**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	0	0	0	0	57	371,149							1,598,802
SUBTOTAL					$ -		$ -		$ 371,149		$ -		$ -		$ -	$ 1,598,802
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	8,266,469	Varies	7,144,861	Varies	6,755,384							38,028,647
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(5,502)	Varies	(8,163)	Varies	(3,883)							(47,488)
SUBTOTAL					$ 8,260,967		$ 7,136,698		$ 6,751,501		$ -		$ -		$ -	$ 37,981,159
TOTAL					$ 8,260,967		$ 7,136,698		$ 7,122,650		$ -		$ -		$ -	$ 39,579,961

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

OCTOBER 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	21,665,516	23,024,616	(1,359,100)	(5 90)	522,126,000	634,960,000	(112,834,000)	(17 77)	4.1495	3.6262	0 52	14 43
2	Hedging Settlement Costs (A2)	1,891,416	3,010,960	(1,119,544)	(37.18)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	5,171	0	5,171	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	23,562,103	26,035,576	(2,473,473)	(9.50)	522,126,000	634,960,000	(112,834,000)	(17.77)	4 5127	4.1003	0 41	10.06
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0 00	0 0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0 00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	14,660,581	10,663,000	3,997,581	37.49	658,001,388	329,194,000	328,807,388	99.88	2.2280	3.2391	(1.01)	(31.22)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0 00	0.00
11	Energy Payments to Qualifying Facilities (A8)	570,643	0	570,643	100.00	20,573,000	0	20,573,000	100.00	2.7737	0.0000	2.77	0.00
12	TOTAL COST OF PURCHASED POWER	15,231,224	10,663,000	4,568,224	42.84	678,574,388	329,194,000	349,380,388	106.13	2.2446	3.2391	(0.99)	(30.70)
13	Total Available MWH (Line 5 + Line 12)	38,793,327	36,698,576	2,094,751	5.71	1,200,700,388	964,154,000	236,546,388	24.53				
14	Fuel Cost of Economy Sales (A6)	(454,942)	(188,000)	(266,942)	141.99	(18,210,087)	(6,964,000)	(11,246,087)	161.49	(2.4983)	(2.6996)	0.20	7.46
15	Gain on Economy Sales (A6)	(72,569)	(30,000)	(42,569)	141.90	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(3,979,423)	(99,000)	(3,880,423)	3,919.62	(276,518,193)	(3,435,000)	(273,083,193)	7,950.02	(1.4391)	(2.8821)	1.44	50.07
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(4,506,934)	(317,000)	(4,189,934)	1,321.75	(294,728,280)	(10,399,000)	(284,329,280)	2,734.20	(1.5292)	(3.0484)	1.52	49.84
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	34,286,393	36,381,576	(2,095,183)	(5.76)	905,972,108	953,755,000	(47,782,892)	(5.01)	3.7845	3.8146	(0.03)	(0.79)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	61,640	63,589	(1,949)	(3.06)	1,628,749	1,667,000	(38,251)	(2 29)	3.7845	3.8146	(0.03)	(0 79)
22	T & D Losses *	885,188	1,852,522	(967,334)	(52 22)	23,389,816	48,564,000	(25,174,184)	(51 84)	3.7845	3.8146	(0 03)	(0.79)
23	TERRITORIAL KWH SALES	34,286,393	36,381,576	(2,095,183)	(5.76)	880,953,543	903,524,000	(22,570,457)	(2.50)	3.8920	4.0266	(0 13)	(3.34)
24	Wholesale KWH Sales	944,419	1,147,256	(202,837)	(17.68)	24,266,224	28,492,000	(4,225,776)	(14.83)	3.8919	4.0266	(0 13)	(3 35)
25	Jurisdictional KWH Sales	33,341,974	35,234,320	(1,892,346)	(5.37)	856,687,319	875,032,000	(18,344,681)	(2.10)	3.8920	4 0266	(0.13)	(3.34)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	33,391,987	35,287,171	(1,895,184)	(5.37)	856,687,319	875,032,000	(18,344,681)	(2.10)	3.8978	4.0327	(0.13)	(3 35)
28	TRUE-UP	(7,617,648)	(7,617,648)	0	0.00	856,687,319	875,032,000	(18,344,681)	(2.10)	(0.8892)	(0.8706)	(0.02)	2 14
29	TOTAL JURISDICTIONAL FUEL COST	25,774,339	27,669,523	(1,895,184)	(6.85)	856,687,319	875,032,000	(18,344,681)	(2.10)	3.0086	3.1621	(0.15)	(4 85)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.0108	3 1644	(0 15)	(4.85)
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	856,687,319	875,032,000	(18,344,681)	(2.10)	0.0063	0.0061	0.00	3.28
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.0171	3.1705	(0.15)	(4.84)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.017	3.171		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: OCTOBER 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 21,665,516
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	5,171
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,891,416
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	14,660,581
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	570,643
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(4,506,934)
10	Total Fuel and Net Power Transactions		$ 34,286,393

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2012
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	287,153,022	391,151,888	(103,998,866)	(26.59)	7,200,982,000	9,037,713,000	(1,836,731,000)	(20.32)	3.9877	4.3280	(0.34)	(7.86)
2	Hedging Settlement Costs (A2)	29,632,015	14,710,150	14,921,865	101.44	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	160,359	0	160,359	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	316,945,396	405,862,038	(88,916,642)	(21.91)	7,200,982,000	9,037,713,000	(1,836,731,000)	(20.32)	4.4014	4.4908	(0.09)	(1.99)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	145,400,270	82,050,000	63,350,270	77.21	8,459,206,552	2,859,943,000	5,599,263,552	195.78	1.7188	2.8689	(1.15)	(40.09)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	5,065,618	0	5,065,618	100.00	177,132,000	0	177,132,000	100.00	2.8598	0.0000	2.86	0.00
12	TOTAL COST OF PURCHASED POWER	150,465,888	82,050,000	68,415,888	83.38	8,636,338,552	2,859,943,000	5,776,395,552	201.98	1.7422	2.8689	(1.13)	(39.27)
13	Total Available MWH (Line 5 + Line 12)	467,411,284	487,912,038	(20,500,754)	(4.20)	15,837,320,552	11,897,656,000	3,939,664,552	33.11				
14	Fuel Cost of Economy Sales (A6)	(2,033,700)	(3,487,000)	1,453,300	(41.68)	(75,747,643)	(97,750,000)	22,002,357	(22.51)	(2.6848)	(3.5673)	0.88	24.74
15	Gain on Economy Sales (A6)	(494,911)	(590,000)	95,089	(16.12)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(89,663,661)	(32,442,000)	(57,221,661)	176.38	(5,829,421,795)	(987,278,000)	(4,842,143,795)	490.45	(1.5381)	(3.2860)	1.75	53.19
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(92,192,272)	(36,519,000)	(55,673,272)	152.45	(5,905,169,438)	(1,085,028,000)	(4,820,141,438)	444.24	(1.5612)	(3.3657)	1.80	53.61
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	375,219,012	451,393,038	(76,174,026)	(16.88)	9,932,151,114	10,812,628,000	(880,476,886)	(8.14)	3.7778	4.1747	(0.40)	(9.51)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	628,666	770,483	(141,817)	(18.41)	16,641,050	18,456,000	(1,814,950)	(9.83)	3.7778	4.1747	(0.40)	(9.51)
22	T & D Losses *	18,996,379	25,828,159	(6,831,780)	(26.45)	502,842,357	618,683,000	(115,840,643)	(18.72)	3.7778	4.1747	(0.40)	(9.51)
23	TERRITORIAL KWH SALES	375,219,011	451,393,038	(76,174,027)	(16.88)	9,412,667,707	10,175,489,000	(762,821,293)	(7.50)	3.9863	4.4361	(0.45)	(10.14)
24	Wholesale KWH Sales	11,016,561	14,538,442	(3,521,881)	(24.22)	276,321,951	326,286,000	(49,964,049)	(15.31)	3.9869	4.4557	(0.47)	(10.52)
25	Jurisdictional KWH Sales	364,202,450	436,854,596	(72,652,146)	(16.63)	9,136,345,756	9,849,203,000	(712,857,244)	(7.24)	3.9863	4.4354	(0.45)	(10.13)
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	364,678,092	437,292,524	(72,614,432)	(16.61)	9,136,345,756	9,849,203,000	(712,857,244)	(7.24)	3.9915	4.4399	(0.45)	(10.10)
28	TRUE-UP	(34,428,546)	(34,428,546)	0	0.00	9,136,345,756	9,849,203,000	(712,857,244)	(7.24)	(0.3768)	(0.3496)	(0.03)	7.78
29	TOTAL JURISDICTIONAL FUEL COST	330,249,546	402,863,978	(72,614,432)	(18.02)	9,136,345,756	9,849,203,000	(712,857,244)	(7.24)	3.6147	4.0903	(0.48)	(11.63)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.6173	4.0932	(0.48)	(11.63)
32	GPIF Reward / (Penalty)	537,930	537,930	0	0.00	9,136,345,756	9,849,203,000	(712,857,244)	(7.24)	0.0059	0.0055	0.00	7.27
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.6232	4.0987	(0.48)	(11.60)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.623	4.099		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$	DIFFERENCE			$	DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	21,455,956.87	22,932,138	(1,476,181.13)	(6.44)	284,749,993.52	389,424,667	(104,674,673.56)	(26.88)
1a	Other Generation	209,559.46	92,478	117,081.46	126.60	2,403,028.70	1,727,221	675,807.70	39.13
2	Fuel Cost of Power Sold	(4,506,934.11)	(317,000)	(4,189,934.11)	(1,321.75)	(92,192,270.40)	(36,519,000)	(55,673,270.40)	(152.45)
3	Fuel Cost - Purchased Power	14,660,581.13	10,663,000	3,997,581.13	37.49	145,400,269.17	82,050,000	63,350,269.17	77.21
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	570,643.00	0	570,643.00	100.00	5,065,617.37	0	5,065,617.37	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,891,416.00	3,010,960	(1,119,544.00)	(37.18)	29,632,015.00	14,710,150	14,921,865.00	101.44
6	Total Fuel & Net Power Transactions	34,281,222.35	36,381,576	(2,100,353.65)	(5.77)	375,058,653.36	451,393,038	(76,334,384.72)	(16.91)
7	AdjustmentsTo Fuel Cost*	5,170.59	0	5,170.59	100.00	160,357.64	0	160,357.64	100.00
8	Adj. Total Fuel & Net Power Transactions	34,286,392.94	36,381,576	(2,095,183.06)	(5.76)	375,219,011.00	451,393,038	(76,174,027.08)	(16.88)
B.	*KWH Sales*								
1	Jurisdictional Sales	856,687,319	875,032,000	(18,344,681)	(2.10)	9,136,345,756	9,849,203,000	(712,857,244)	(7.24)
2	Non-Jurisdictional Sales	24,266,224	28,492,000	(4,225,776)	(14.83)	276,321,951	326,286,000	(49,964,049)	(15.31)
3	Total Territorial Sales	880,953,543	903,524,000	(22,570,457)	(2.50)	9,412,667,707	10,175,489,000	(762,821,293)	(7.50)
4	Juris. Sales as % of Total Terr. Sales	97.2455	96.8466	0.3989	0.41	97.0644	96.7934	0.2710	0.28

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$	*DIFFERENCE*			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	31,184,351.13	31,894,916	(710,565.27)	(2.23)	381,468,973.34	419,047,109	(37,578,135.30)	(8.97)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	7,617,648.00	7,617,648	0.00	0.00	34,428,544.76	34,428,545	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(537,538.80)	(537,539)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	38,748,245.25	39,458,811	(710,565.75)	(1.80)	415,359,979.30	452,938,115	(37,578,135.70)	(8.30)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	34,286,392.94	36,381,576	(2,095,183.06)	(5.76)	375,219,011.00	451,393,038	(76,174,027.00)	(16.88)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2455	96.8466	0.3989	0.41	97.0644	96.7934	0.2710	0.28
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	33,391,987.21	35,287,171	(1,895,183.79)	(5.37)	364,678,092.14	437,292,524	(72,614,431.86)	(16.61)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	5,356,258.04	4,171,640	1,184,618.04	(28.40)	50,681,887.16	15,645,591	35,036,296.16	(223.94)
8	Interest Provision for the Month	2,623.45	(2,796)	5,419.45	193.83	29,413.34	(17,835)	47,248.34	264.92
9	Beginning True-Up & Interest Provision	28,458,330.95	(27,403,170)	55,861,500.95	203.85	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(7,617,648.00)	(7,617,648)	0.00	0.00	(34,428,544.76)	(34,428,545)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	26,199,564.44	(30,851,974)	57,051,538.44	184.92	26,211,449.43	(30,851,974)	57,063,423.43	184.96
12	Adjustment*	0.00	0	0.00	0.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	26,199,564.44	(30,851,974)	57,051,538.44	184.92	26,199,564.44	(30,851,974)	57,051,538.44	184.92

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

		CURRENT MONTH			
				DIFFERENCE	
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	28,458,330.95	(27,403,170)	55,861,500.95	(203.85)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	26,196,940.99	(30,849,178)	57,046,118.99	(184.92)
3	Total of Beginning & Ending True-Up Amts.	54,655,271.94	(58,252,348)	112,907,619.94	(193.83)
4	Average True-Up Amount	27,327,635.97	(29,126,174)	56,453,809.97	(193.83)
	Interest Rate				
5	1st Day of Reporting Business Month	0.09	0.09	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.14	0.14	0.0000	
7	Total (D5+D6)	0.23	0.23	0.0000	
8	Annual Average Interest Rate	0.12	0.12	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0096	0.0096	0.0000	
10	Interest Provision (D4*D9)	2,623.45	(2,796)	5,419.45	(193.83)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	75,953	67,691	8,262	12.21	1,645,237	603,567	1,041,670	172.59
2	COAL	11,340,907	13,067,470	(1,726,563)	(13.21)	186,477,501	288,864,542	(102,387,041)	(35.44)
3	GAS	9,988,735	9,831,349	157,386	1.60	95,296,788	101,087,931	(5,791,143)	(5.73)
4	GAS (B.L.)	125,717	0	125,717	100.00	2,901,687	-	2,901,687	100.00
5	LANDFILL GAS	61,117	58,106	3,011	5.18	610,517	571,564	38,953	6.82
6	OIL - C.T.	73,087	0	73,087	100.00	221,292	24,285	197,007	811.23
7	TOTAL ($)	21,665,516	23,024,616	(1,359,100)	(5.90)	287,153,022	391,151,888	(103,998,866)	(26.59)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	221,089	245,888	(24,799)	(10.09)	3,603,948	5,820,647	(2,216,699)	(38.08)
10	GAS	298,736	386,832	(88,096)	(22.77)	3,575,227	3,194,936	380,291	11.90
11	LANDFILL GAS	2,070	2,240	(170)	(7.59)	21,105	22,034	(929)	(4.22)
12	OIL - C.T.	231	0	231	100.00	702	96	606	631.25
13	TOTAL (MWH)	522,126	634,960	(112,834)	(17.77)	7,200,982	9,037,713	(1,836,731)	(20.32)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	561	572	(11)	(1.92)	12,853	4,735	8,118	171.44
15	COAL (TONS)	108,990	118,840	(9,850)	(8.29)	1,725,379	2,746,710	(1,021,331)	(37.18)
16	GAS (MCF) (1)	2,085,641	2,636,059	(550,418)	(20.88)	26,235,769	22,088,504	4,147,265	18.78
17	OIL - C.T. (BBL)	685	0	685	100.00	2,125	231	1,894	819.91
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,514,111	2,817,071	(302,960)	(10.75)	41,108,990	67,251,375	(26,142,385)	(38.87)
19	GAS - Generation (1)	2,108,833	2,715,141	(606,308)	(22.33)	25,558,153	22,751,158	2,806,995	12.34
20	OIL - C.T.	4,025	0	4,025	100.00	12,390	1,350	11,040	817.78
21	TOTAL (MMBTU)	4,626,969	5,532,212	(905,243)	(16.36)	66,679,533	90,003,883	(23,324,350)	(25.91)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	42.34	38.72	3.62	9.35	50.05	64.41	(14.36)	(22.29)
24	GAS	57.22	60.93	(3.71)	(6.09)	49.65	35.35	14.30	40.45
25	LANDFILL GAS	0.40	0.35	0.05	14.29	0.29	0.24	0.05	20.83
26	OIL - C.T.	0.04	0.00	0.04	100.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	135.39	118.34	17.05	14.41	128.00	127.46	0.54	0.42
29	COAL ($/TON)	104.05	109.96	(5.91)	(5.37)	108.08	105.17	2.91	2.77
30	GAS ($/MCF) (1)	4.75	3.68	1.07	29.08	3.65	4.49	(0.84)	(18.71)
31	OIL - C.T. ($/BBL)	106.70	0.00	106.70	100.00	104.14	105.13	(0.99)	(0.94)
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.59	4.66	(0.07)	(1.50)	4.65	4.30	0.35	8.14
33	GAS - Generation (1)	4.64	3.58	1.06	29.61	3.63	4.36	(0.73)	(16.74)
34	OIL - C.T.	18.16	0.00	18.16	100.00	17.86	17.99	(0.13)	(0.72)
35	TOTAL ($/MMBTU)	4.62	4.13	0.49	11.86	4.26	4.32	(0.06)	(1.39)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,371	11,457	(86)	(0.75)	11,407	11,554	(147)	(1.27)
37	GAS - Generation (1)	7,222	7,071	151	2.14	7,302	7,216	86	1.19
38	OIL - C.T.	17,424	0	17,424	100.00	17,650	14,063	3,587	25.51
39	TOTAL (BTU/KWH)	9,014	8,783	231	2.63	9,385	10,030	(645)	(6.43)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.22	5.34	(0.12)	(2.25)	5.30	4.97	0.33	6.64
41	GAS	3.34	2.54	0.80	31.50	2.67	3.16	(0.49)	(15.51)
42	LANDFILL GAS	2.95	2.59	0.36	13.90	2.89	2.59	0.30	11.58
43	OIL - C.T.	31.64	0.00	31.64	100.00	31.52	25.30	6.22	24.58
44	TOTAL (¢/KWH)	4.15	3.63	0.52	14.33	3.99	4.33	(0.34)	(7.85)

Note (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(1,003)	(1.8)	99.7	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,015	0	0	0.00	0.00
3									Gas-S	0	1,015	0	0		0.00
4									Oil-S	0	138,572	0	0		0.00
5	Crist 5		75	29,382	52.7	100.0	52.7	11,851	Coal	14,919	11,670	348,218	1,509,381	5.14	101.17
6				-					Gas-G	0	1,015	0	0	0.00	0.00
7									Gas-S	29	1,015	29	930		32.08
8									Oil-S	61	138,572	356	7,355		120.57
9	Crist 6		291	131,626	60.8	90.6	67.1	10,843	Coal	61,066	11,686	1,427,233	6,177,989	4.69	101.17
10				0					Gas-G	0	1,015	0	0	0.00	0.00
11									Gas-S	3,842	1,015	3,900	124,787		32.48
12									Oil-S	17	138,572	101	2,088		122.82
13	Crist 7		465	(717)	(0.2)	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
14				0					Gas-G	0	1,015	0	0	0.00	0.00
15									Gas-S	0	1,015	0	0		0.00
16									Oil-S	0	138,572	0	0		0.00
17	Scholz 1		46	(228)	(0.7)	66.6	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(157)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	(651)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
22									Oil-S	0	139,900	0	0		0.00
23	Smith 2		195	52,751	36.4	100.0	36.4	11,203	Coal	25,182	11,734	590,972	2,854,785	5.41	113.37
24									Oil-S	127	139,900	747	17,597		138.56
25	Smith 3		558	292,000	70.3	99.6	82.2	7,222	Gas-G	2,081,770	1,013	2,108,833	9,779,176	3.35	4.70
26	Smith A	(2)	36	231	0.9	98.6	59.5	17,429	Oil	685	139,890	4,026	73,087	31.64	106.70
27	Other Generation			6,736									209,559	3.11	0.00
28	Perdido			2,070					Landfill Gas				61,117	2.95	0.00
29	Daniel 1	(1)	510	11,000	2.9	99.4	58.5	12,769	Coal	7,823	8,978	140,461	802,811	7.30	102.62
30									Oil-S	356	140,057	2,093	48,913		137.40
31	Daniel 2	(1)	510	(914)	(0.2)	91.1	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	140,057	0	0		0.00
33	Total		2,969	522,126	23.6	81.2	36.5	9,014				4,626,969	21,669,575	4.15	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation, Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
	Recoverable Fuel	21,665,516	4.15

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	887	1,339	(452)	(33.76)	14,089	15,071	(982)	(6.52)
3	UNIT COST ($/BBL)	147.60	118.10	29.50	24.98	132.10	126.43	5.67	4.48
4	AMOUNT ($)	130,921	158,134	(27,213)	(17.21)	1,861,130	1,905,370	(44,240)	(2.32)
5	*BURNED:*								
6	UNITS (BBL)	587	572	15	2.62	13,273	4,736	8,537	180.26
7	UNIT COST ($/BBL)	135.33	118.34	16.99	14.36	128.16	127.44	0.72	0.56
8	AMOUNT ($)	79,441	67,691	11,750	17.36	1,701,119	603,567	1,097,552	181.84
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	6,204	11,292	(5,088)	(45.06)	6,204	11,292	(5,088)	(45.06)
11	UNIT COST ($/BBL)	128.81	118.70	10.11	8.52	128.81	118.70	10.11	8.52
12	AMOUNT ($)	799,168	1,340,392	(541,224)	(40.38)	799,168	1,340,392	(541,224)	(40.38)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	164,087	158,700	5,387	3.39	1,705,712	2,430,566	(724,854)	(29.82)
16	UNIT COST ($/TON)	106.33	121.84	(15.51)	(12.73)	107.27	109.93	(2.66)	(2.42)
17	AMOUNT ($)	17,446,859	19,336,350	(1,889,491)	(9.77)	182,975,877	267,191,749	(84,215,872)	(31.52)
18	*BURNED:*								
19	UNITS (TONS)	108,990	118,840	(9,850)	(8.29)	1,725,379	2,746,710	(1,021,331)	(37.18)
20	UNIT COST ($/TON)	104.09	109.96	(5.87)	(5.34)	107.48	105.17	2.31	2.20
21	AMOUNT ($)	11,344,966	13,067,470	(1,722,504)	(13.18)	185,439,249	288,864,541	(103,425,292)	(35.80)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	881,680	899,205	(17,525)	(1.95)	881,680	899,205	(17,525)	(1.95)
24	UNIT COST ($/TON)	104.07	117.94	(13.87)	(11.76)	104.07	117.94	(13.87)	(11.76)
25	AMOUNT ($)	91,760,468	106,052,149	(14,291,681)	(13.48)	91,760,468	106,052,149	(14,291,681)	(13.48)
26	DAYS SUPPLY	42	43	(1)	(2.33)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,094,436	2,715,141	(620,705)	(22.86)	26,350,981	22,751,158	3,599,823	15.82
29	UNIT COST ($/MMBTU)	4.83	3.59	1.24	34.54	3.62	4.42	(0.80)	(18.10)
30	AMOUNT ($)	10,114,898	9,738,871	376,027	3.86	95,506,421	100,650,164	(5,143,743)	(5.11)
31	*BURNED:*								
32	UNITS (MMBTU)	2,112,762	2,715,141	(602,379)	(22.19)	26,610,943	22,751,158	3,859,785	16.97
33	UNIT COST ($/MMBTU)	4.69	3.59	1.10	30.64	3.60	4.42	(0.82)	(18.55)
34	AMOUNT ($)	9,904,893	9,738,871	166,022	1.70	95,795,447	100,650,164	(4,854,717)	(4.82)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	769,616	0	769,616	100.00	769,616	0	769,616	100.00
37	UNIT COST ($/MMBTU)	4.64	0.00	4.64	100.00	4.64	0.00	4.64	100.00
38	AMOUNT ($)	3,568,898	0	3,568,898	100.00	3,568,898	0	3,568,898	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	354	0	354	100.00	1,418	767	651	84.88
41	UNIT COST ($/BBL)	137.68	0.00	137.68	100.00	135.30	118.27	17.00	14.37
42	AMOUNT ($)	48,738	0	48,738	100.00	191,849	90,715	101,134	111.49
43	*BURNED:*								
44	UNITS (BBL)	685	0	685	100.00	2,125	231	1,894	819.91
45	UNIT COST ($/BBL)	106.70	0.00	106.70	100.00	104.14	105.13	(0.99)	(0.94)
46	AMOUNT ($)	73,087	0	73,087	100.00	221,292	24,285	197,007	811.23
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,120	7,058	(938)	(13.29)	6,120	7,058	(938)	(13.29)
49	UNIT COST ($/BBL)	106.69	104.99	1.70	1.62	106.69	104.99	1.70	1.62
50	AMOUNT ($)	652,952	741,007	(88,055)	(11.88)	652,952	741,007	(88,055)	(11.88)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		3,435,000	0	3,435,000	2.88	3.20	99,000	110,000
2	Various	Economy Sales	6,964,000	0	6,964,000	2.70	3.10	188,000	216,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	30,000	30,000
4	TOTAL ESTIMATED SALES		10,399,000	0	10,399,000	3.05	3.42	317,000	356,000
	ACTUAL								
5	Southern Company Interchange		165,281,829	0	165,281,829	2.67	2.90	4,413,296	4,794,474
6	A.E.C.	External	1,954,939	0	1,954,939	2.47	3.13	48,384	61,226
7	AECI	External	49,329	0	49,329	2.41	3.65	1,187	1,801
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	337,992	0	337,992	2.31	3.02	7,794	10,191
13	CARGILE	External	1,839,780	0	1,839,780	2.99	2.80	55,096	51,564
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	756,686	0	756,686	2.70	2.89	20,417	21,854
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	1,212,132	0	1,212,132	2.62	3.70	31,703	44,788
19	EAGLE EN	External	873,307	0	873,307	2.38	3.21	20,781	28,074
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	73,635	0	73,635	2.53	3.98	1,861	2,932
22	ENTERGY	External	0	0	0	0.00	0.00	(23)	0
23	FPC	External	2,535	0	2,535	2.06	2.90	52	74
24	FPL	External	105,032	0	105,032	4.46	4.40	4,687	4,623
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	366,916	0	366,916	2.31	2.98	8,492	10,925
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	148,717	0	148,717	6.58	2.84	9,790	4,221
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	0	0	0	0.00	0.00	0	0
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	869,272	0	869,272	2.32	3.03	20,145	26,339
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	1,587,307	0	1,587,307	2.51	3.94	39,800	62,553
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	453,837	0	453,837	2.87	3.98	13,016	18,065
40	SEC	External	1,170,409	0	1,170,409	2.56	3.33	29,997	38,949
41	SEPA	External	2,979,181	0	2,979,181	2.10	2.58	62,430	76,731
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	389,870	0	389,870	2.76	3.53	10,752	13,745
44	TEA	External	2,835,454	0	2,835,454	2.25	2.96	63,720	84,043
45	TECO	External	0	0	0	0.00	0.00	0	0
46	TENASKA	External	0	0	0	0.00	0.00	0	0
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	151,757	0	151,757	2.39	3.21	3,628	4,868
49	UPP	External	0	0	0	0.00	0.00	0	0
50	WRI	External	52,000	0	52,000	2.37	2.55	1,232	1,326
51	Less: Flow-Thru Energy		(18,210,087)	0	(18,210,087)	2.38	2.38	(433,873)	(433,873)
52	SEPA		913,792	913,792	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	72,569	72,569
54	Other transactions including adj.		128,532,659	119,486,992	9,045,667	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		294,728,280	120,400,784	174,327,496	1.53	1.67	4,506,934	4,929,491
56	Difference in Amount		284,329,280	120,400,784	163,928,496	(1.52)	(1.75)	4,189,934	4,573,491
57	Difference in Percent		2,734.20	0.00	1,576.39	(49.84)	(51.17)	1,321.75	1,284.69

Note. (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

PERIOD TO DATE

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) ¢ / KWH FUEL COST	(6) (b) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		967,278,000	0	967,278,000	3.29	3.68	32,442,000	36,288,000
2	Various	Economy Sales	97,750,000	0	97,750,000	3.57	3.98	3,487,000	3,893,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	590,000	212,000
4	TOTAL ESTIMATED SALES		1,065,028,000	0	1,065,028,000	3.37	3.72	36,519,000	40,393,000
	ACTUAL								
5	Southern Company Interchange		3,614,183,586	0	3,614,183,586	2.54	2.77	91,669,020	99,972,975
6	A.E.C.	External	4,063,958	0	4,063,958	2.77	3.48	112,774	141,445
7	AECI	External	73,639	0	73,639	2.29	3.53	1,689	2,598
8	AEP	External	6,304	0	6,304	3.40	5.50	214	347
9	AMERENEM	External	23,592	0	23,592	0.00	4.10	0	967
10	ARCLIGHT	External	22,685	0	22,685	6.98	4.92	1,584	1,117
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	673,360	0	673,360	2.65	3.50	17,867	23,569
13	CARGILE	External	3,888,485	0	3,888,485	2.64	3.08	102,834	119,666
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	1,268,964	0	1,268,964	2.45	2.94	31,123	37,315
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	4,751,532	0	4,751,532	2.32	3.34	110,041	158,489
19	EAGLE EN	External	1,501,998	0	1,501,998	2.48	3.40	37,246	51,139
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	113,604	0	113,604	2.36	3.95	2,684	4,484
22	ENTERGY	External	14,920,480	0	14,920,480	3.36	6.79	500,907	1,012,864
23	FPC	External	517,520	0	517,520	3.41	5.21	17,673	26,945
24	FPL	External	4,174,182	0	4,174,182	2.83	4.05	118,182	168,846
25	JARON	External	228,847	0	228,847	3.31	5.04	7,586	11,525
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	944,921	0	944,921	2.71	3.55	25,647	33,577
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	1,130,722	0	1,130,722	2.98	3.32	33,671	37,536
32	NCEMC	External	13,974	0	13,974	1.95	2.83	272	395
33	NCMPA1	External	282,871	0	282,871	2.48	2.95	7,014	8,353
34	NRG	External	75,066	0	75,066	3.68	5.03	2,763	3,776
35	OPC	External	1,490,016	0	1,490,016	2.43	3.30	36,252	49,190
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	10,002,236	0	10,002,236	2.16	3.27	215,556	327,442
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	3,898,778	0	3,898,778	3.18	4.53	123,918	176,704
40	SEC	External	2,000,772	0	2,000,772	2.45	3.18	48,942	63,285
41	SEPA	External	6,607,179	0	6,607,179	2.33	2.89	153,743	191,104
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	2,397,915	0	2,397,915	3.32	4.48	79,498	107,458
44	TEA	External	8,819,734	0	8,819,734	2.24	3.12	197,271	275,094
45	TECO	External	411,994	0	411,994	2.53	3.84	10,407	15,820
46	TENASKA	External	30,742	0	30,742	3.11	4.37	957	1,342
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	1,046,170	0	1,046,170	2.61	3.81	27,280	39,895
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	196,297	0	196,297	2.62	3.50	5,153	6,880
51	Less Flow-Thru Energy		(75,445,879)	0	(75,445,879)	2.68	2.66	(2,005,359)	(2,005,359)
52	SEPA		11,443,694	11,443,694	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	494,910	494,910
54	Other transactions including adj		2,279,240,394	1,734,833,345	544,407,049	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		5,905,169,438	1,746,277,039	4,158,892,399	1.56	1.71	92,192,270	101,070,431
56	Difference in Amount		4,820,141,438	1,746,277,039	3,073,864,399	(1.81)	(2.01)	55,673,270	60,677,431
57	Difference in Percent		444.24	0.00	283.30	(53.71)	(54.03)	152.45	150.22

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: OCTOBER 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

CURRENT MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	20,556,000	0	0	0	2.77	2.77	570,167
6 International Paper	COG 1	17,000	0	0	0	2.80	2.80	476
7 TOTAL		20,573,000	0	0	0	2.77	2.77	570,643

PERIOD-TO-DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	52
5 Ascend Performance Materials	COG 1	171,988,000	0	0	0	2.75	2.75	4,722,761
6 International Paper	COG 1	918,000	0	0	0	2.80	2.80	25,732
7 TOTAL		177,132,000	0	0	0	2.86	2.86	5,065,617

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	287,747,000	3.23	9,280,000	1,011,345,000	3.77	38,109,000
2	Economy Energy	5,623,000	3.17	178,000	45,862,000	3.97	1,819,000
3	Other Purchases	35,824,000	3.36	1,205,000	1,802,736,000	2.34	42,122,000
4	TOTAL ESTIMATED PURCHASES	329,194,000	3.24	10,663,000	2,859,943,000	2.87	82,050,000
	ACTUAL						
5	Southern Company Interchange	142,240,236	2.86	4,071,105	754,474,142	2.73	20,626,354
6	Non-Associated Companies	45,283,391	0.81	366,770	299,131,899	(0.85)	(2,547,602)
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	391,244,000	2.73	10,675,565	5,286,800,000	2.44	129,248,033
9	Other Wheeled Energy	32,785,000	0.00	N/A	798,986,000	0.00	N/A
10	Other Transactions	64,658,848	0.03	22,584	1,395,260,390	0.02	276,084
11	Less: Flow-Thru Energy	(18,210,087)	2.61	(475,443)	(75,445,879)	2.92	(2,202,599)
12	TOTAL ACTUAL PURCHASES	658,001,388	2.23	14,660,581	8,459,206,552	1.72	145,400,270
13	Difference in Amount	328,807,388	(1.01)	3,997,581	5,599,263,552	(1.15)	63,350,270
14	Difference in Percent	99.88	(31.17)	37.49	195.78	(40.07)	77.21

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	781,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,892	0	0	1,227,653
SUBTOTAL					$ 781,448		$ 152,312		$ 267,339		$ 10,862		$ 5,892		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					$ 2,379,394		$ 1,733,195		$ 1,750,407		$ 1,484,274		$ 2,071,953		$ 7,640,423	$ 17,059,646

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

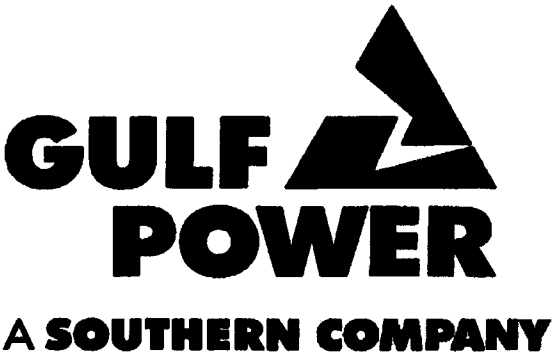
	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	0	0	0	0	57	371,149	(116.5)	(84,799)					1,514,003
SUBTOTAL					$ -		$ -		$ 371,149		$ (84,799)		$ -		$ -	$ 1,514,003
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	8,266,469	Varies	7,144,861	Varies	6,755,384	Varies	1,978,232					40,006,879
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(5,502)	Varies	(8,163)	Varies	(3,883)	Varies	(3,087)					(50,575)
SUBTOTAL					$ 8,260,967		$ 7,136,698		$ 6,751,501		$ 1,975,145		$ -		$ -	$ 39,956,304
TOTAL					$ 8,260,967		$ 7,136,698		$ 7,122,650		$ 1,890,346		$ -		$ -	$ 41,470,307

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 120001-EI

MONTHLY FUEL FILING

NOVEMBER 2012



SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	24,880,439	19,400,708	5,279,731	27.21	602,668,000	516,951,000	85,717,000	16.58	4.0952	3.7529	0.34	9.12
2	Hedging Settlement Costs (A2)	1,288,335	1,947,430	(679,095)	(34.87)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	10,903	0	10,903	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	25,959,677	21,348,138	4,611,539	21.60	602,668,000	516,951,000	85,717,000	16.58	4.3075	4.1296	0.18	4.31
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	17,872,392	11,542,000	6,330,392	54.85	685,268,478	439,747,000	245,519,478	55.83	2.6081	2.6247	(0.02)	(0.63)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	551,763	0	551,763	100.00	17,659,000	0	17,659,000	100.00	3.1245	0.0000	3.12	0.00
12	TOTAL COST OF PURCHASED POWER	18,424,155	11,542,000	6,882,155	59.63	702,925,478	439,747,000	263,178,478	59.85	2.6211	2.6247	(0.00)	(0.14)
13	Total Available MWH (Line 5 + Line 12)	44,383,832	32,890,138	11,493,694	34.95	1,305,593,478	956,698,000	348,895,478	36.47				
14	Fuel Cost of Economy Sales (A6)	(371,739)	(190,000)	(181,739)	95.65	(12,583,441)	(8,185,000)	(4,378,441)	53.49	(2.9589)	(2.3213)	(0.64)	(27.47)
15	Gain on Economy Sales (A6)	(25,477)	(29,000)	3,523	(12.15)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(10,207,840)	(2,899,000)	(7,308,840)	252.12	(497,621,803)	(135,080,000)	(362,541,803)	268.39	(2.0513)	(2.1481)	0.09	4.42
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(10,605,056)	(3,118,000)	(7,487,056)	240.12	(510,185,244)	(143,265,000)	(366,920,244)	256.11	(2.0787)	(2.1784)	0.10	4.49
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	33,778,776	29,772,138	4,006,638	13.46	795,408,234	813,433,000	(18,024,766)	(2.22)	4.2467	3.6601	0.59	16.03
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	89,327	55,231	14,096	25.52	1,632,468	1,509,000	123,468	8.18	4.2467	3.6601	0.59	16.03
22	T & D Losses *	1,226,029	1,310,609	(84,580)	(6.45)	28,870,159	35,808,000	(6,937,841)	(19.38)	4.2467	3.6601	0.59	16.03
23	TERRITORIAL KWH SALES	33,778,777	29,772,138	4,006,638	13.46	764,905,589	776,116,000	(11,210,411)	(1.44)	4.4161	3.8360	0.58	15.12
24	Wholesale KWH Sales	1,023,599	1,038,874	(13,275)	(1.28)	23,178,568	27,030,000	(3,851,432)	(14.25)	4.4161	3.8360	0.58	15.12
25	Jurisdictional KWH Sales	32,755,178	28,735,264	4,019,914	13.99	741,727,021	749,086,000	(7,358,979)	(0.98)	4.4161	3.8360	0.58	15.12
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	32,804,311	28,778,367	4,025,944	13.99	741,727,021	749,086,000	(7,358,979)	(0.98)	4.4227	3.8418	0.58	15.12
28	TRUE-UP	(7,617,648)	(7,617,648)	0	0.00	741,727,021	749,086,000	(7,358,979)	(0.98)	(1.0270)	(1.0169)	(0.01)	0.99
29	TOTAL JURISDICTIONAL FUEL COST	25,186,663	21,160,719	4,025,944	19.03	741,727,021	749,086,000	(7,358,979)	(0.98)	3.3957	2.8249	0.57	20.21
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.3981	2.8289	0.57	20.21
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	741,727,021	749,086,000	(7,358,979)	(0.98)	0.0073	0.0072	0.00	1.39
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.4054	2.8361	0.57	20.16
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.405	2.834		

*Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: NOVEMBER 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 24,680,439
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	10,903
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,268,335
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	17,872,392
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	551,763
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(10,605,056)
10	Total Fuel and Net Power Transactions		$ 33,778,776

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	311,633,461	410,552,596	(98,719,135)	(24.05)	7,803,650,000	9,554,664,000	(1,751,014,000)	(18.33)	3.9960	4.2989	(0.30)	(7.00)
2	Hedging Settlement Costs (A2)	30,900,350	16,657,580	14,242,770	85.50	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	171,262	0	171,262	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	342,905,073	427,210,176	(84,305,103)	(19.73)	7,803,650,000	9,554,664,000	(1,751,014,000)	(18.33)	4.3942	4.4712	(0.08)	(1.72)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	163,272,662	93,592,000	69,680,662	74.45	9,144,473,030	3,299,690,000	5,844,783,030	177.13	1.7855	2.8364	(1.05)	(37.05)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	5,617,381	0	5,617,381	100.00	194,791,000	0	194,791,000	100.00	2.8835	0.0000	2.88	0.00
12	TOTAL COST OF PURCHASED POWER	168,890,043	93,592,000	75,298,043	80.45	9,339,264,030	3,299,690,000	6,039,574,030	183.03	1.8084	2.8364	(1.03)	(36.24)
13	Total Available MWH (Line 5 + Line 12)	511,795,118	520,802,176	(9,007,060)	(1.73)	17,142,914,030	12,854,354,000	4,288,560,030	33.36				
14	Fuel Cost of Economy Sales (A6)	(2,405,439)	(3,677,000)	1,271,561	(34.58)	(88,311,084)	(105,935,000)	17,623,916	(16.64)	(2.7238)	(3.4710)	0.75	21.53
15	Gain on Economy Sales (A6)	(520,388)	(619,000)	98,612	(15.93)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(99,871,501)	(35,341,000)	(64,530,501)	182.59	(6,327,043,598)	(1,122,358,000)	(5,204,685,598)	463.73	(1.5785)	(3.1488)	1.57	49.87
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(102,797,328)	(39,637,000)	(63,160,328)	159.35	(6,415,354,682)	(1,228,293,000)	(5,187,061,682)	422.30	(1.6024)	(3.2270)	1.62	50.34
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	408,997,788	481,165,178	(72,167,388)	(15.00)	10,727,559,348	11,626,061,000	(898,501,652)	(7.73)	3.8128	4.1387	(0.33)	(7.88)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	696,697	828,291	(129,594)	(15.68)	18,273,536	19,965,000	(1,691,464)	(8.47)	3.8128	4.1387	(0.33)	(7.88)
22	T & D Losses *	20,272,071	27,087,419	(6,815,348)	(25.16)	531,712,518	654,491,000	(122,778,464)	(18.76)	3.8128	4.1387	(0.33)	(7.88)
23	TERRITORIAL KWH SALES	408,997,788	481,185,178	(72,187,388)	(15.00)	10,177,573,296	10,951,605,000	(774,031,704)	(7.07)	4.0186	4.3936	(0.38)	(8.54)
24	Wholesale KWH Sales	12,040,180	15,575,318	(3,535,158)	(22.70)	299,500,519	353,316,000	(53,815,481)	(15.23)	4.0201	4.4083	(0.39)	(8.81)
25	Jurisdictional KWH Sales	396,957,828	465,589,860	(68,632,232)	(14.74)	9,876,072,777	10,598,289,000	(720,216,223)	(6.80)	4.0186	4.3931	(0.37)	(8.52)
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	397,462,403	466,070,891	(68,588,488)	(14.72)	9,876,072,777	10,598,289,000	(720,216,223)	(6.80)	4.0239	4.3978	(0.37)	(8.50)
28	TRUE-UP	(42,048,194)	(42,048,194)	0	0.00	9,876,072,777	10,598,289,000	(720,216,223)	(6.80)	(0.4257)	(0.3967)	(0.03)	7.31
29	TOTAL JURISDICTIONAL FUEL COST	355,438,209	424,024,697	(68,588,488)	(16.18)	9,876,072,777	10,598,289,000	(720,216,223)	(6.80)	3.5962	4.0009	(0.40)	(10.07)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.6008	4.0038	(0.40)	(10.07)
32	GPIF Reward / (Penalty)	591,723	591,723	0	0.00	9,876,072,777	10,598,289,000	(720,218,223)	(6.80)	0.0060	0.0056	0.00	7.14
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.6068	4.0094	(0.40)	(10.04)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.607	4.009		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	24,467,330.71	19,221,895	5,245,435.71	27.29	309,217,324.23	408,646,562	(99,429,237.85)	(24.33)
1a	Other Generation	213,108.44	178,813	34,295.44	19.18	2,616,137.14	1,906,034	710,103.14	37.26
2	Fuel Cost of Power Sold	(10,605,056.18)	(3,118,000)	(7,487,056.18)	(240.12)	(102,797,326.58)	(39,637,000)	(63,160,326.58)	(159.35)
3	Fuel Cost - Purchased Power	17,872,392.10	11,542,000	6,330,392.10	54.85	163,272,661.27	93,592,000	69,680,661.27	74.45
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	551,763.45	0	551,763.45	100.00	5,617,380.82	0	5,617,380.82	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,268,335.00	1,947,430	(679,095.00)	(34.87)	30,900,350.00	16,657,580	14,242,770.00	85.50
6	Total Fuel & Net Power Transactions	33,767,873.52	29,772,138	3,995,735.52	13.42	408,826,526.88	481,165,176	(72,338,649.20)	(15.03)
7	AdjustmentsTo Fuel Cost*	10,903.24	0	10,903.24	100.00	171,260.88	0	171,260.88	100.00
8	Adj. Total Fuel & Net Power Transactions	33,778,776.76	29,772,138	4,006,638.76	13.46	408,997,787.76	481,165,176	(72,167,388.32)	(15.00)
B.	*KWH Sales*								
1	Jurisdictional Sales	741,727,021	749,086,000	(7,358,979)	(0.98)	9,878,072,777	10,598,289,000	(720,216,223)	(6.80)
2	Non-Jurisdictional Sales	23,178,568	27,030,000	(3,851,432)	(14.25)	299,500,519	353,316,000	(53,815,481)	(15.23)
3	Total Territorial Sales	764,905,589	776,116,000	(11,210,411)	(1.44)	10,177,573,298	10,951,605,000	(774,031,704)	(7.07)
4	Juris. Sales as % of Total Terr. Sales	96.9697	96.5173	0.4524	0.47	97.0573	96.7738	0.2835	0.29

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 180 of 209

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	28,955,131.28	27,304,185	(349,053.42)	(1.28)	408,424,104.62	446,351,293	(37,927,188.72)	(8.50)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	7,617,648.00	7,617,648	0.00	0.00	42,046,192.76	42,046,193	0.00	0.00
2b	Incentive Provision	(53,753.88)	(53,754)	0.00	0.00	(591,292.68)	(591,293)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	34,519,025.40	34,868,079	(349,053.60)	(1.00)	449,879,004.70	487,806,193	(37,927,188.30)	(7.78)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	33,778,776.76	29,772,138	4,006,638.76	13.46	408,997,787.76	481,165,176	(72,167,388.24)	(15.00)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.9697	96.5173	0.4524	0.47	97.0573	96.7738	0.2835	0.29
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	32,804,311.26	28,778,367	4,025,944.26	13.99	397,482,403.40	466,070,891	(68,588,487.60)	(14.72)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	1,714,714.14	6,089,712	(4,374,997.86)	71.84	52,396,601.30	21,735,303	30,661,298.30	(141.07)
8	Interest Provision for the Month	2,906.01	(3,952)	6,858.01	173.53	32,319.35	(21,787)	54,106.35	248.34
9	Beginning True-Up & Interest Provision	26,199,564.44	(30,851,974)	57,051,538.44	184.92	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(7,617,648.00)	(7,617,648)	0.00	0.00	(42,046,192.76)	(42,046,193)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	20,299,536.59	(32,383,862)	52,683,398.59	162.68	20,311,421.58	(32,383,862)	52,695,283.58	162.72
12	Adjustment*	0.00	0	0.00	0.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	20,299,536.59	(32,383,862)	52,683,398.59	162.68	20,299,536.59	(32,383,862)	52,683,398.59	162.68

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

		CURRENT MONTH			
			$	*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	26,199,564.44	(30,851,974)	57,051,536.44	(184.92)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	20,296,630.58	(32,379,910)	52,676,540.58	(162.68)
3	Total of Beginning & Ending True-Up Amts.	46,496,195.02	(63,231,884)	109,728,079.02	(173.53)
4	Average True-Up Amount	23,248,097.51	(31,615,942)	54,864,039.51	(173.53)
	Interest Rate				
5	1st Day of Reporting Business Month	0.14	0.14	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.16	0.16	0.0000	
7	Total (D5+D6)	0.30	0.30	0.0000	
8	Annual Average Interest Rate	0.15	0.15	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0125	0.0125	0.0000	
10	Interest Provision (D4*D9)	2,906.01	(3,952)	6,858.01	(173.53)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

		CURRENT MONTH		DIFFERENCE		PERIOD - TO - DATE		DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	110,409	67,646	42,763	63.22	1,755,646	671,213	1,084,433	161.56
2	COAL	14,345,395	12,101,319	2,244,076	18.54	200,822,896	300,965,861	(100,142,965)	(33.27)
3	GAS	10,113,397	7,175,557	2,937,840	40.94	105,410,185	108,263,488	(2,853,303)	(2.64)
4	GAS (B.L.)	53,829	0	53,829	100.00	2,955,516	-	2,955,516	100.00
5	LANDFILL GAS	57,409	56,186	1,223	2.18	667,926	627,750	40,176	6.40
6	OIL - C.T.	0	0	0	0.00	221,292	24,285	197,007	811.23
7	TOTAL ($)	24,680,439	19,400,708	5,279,731	27.21	311,833,461	410,552,596	(98,719,135)	(24.05)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	274,808	222,471	52,337	23.53	3,878,756	6,043,118	(2,164,362)	(35.82)
10	GAS	325,885	292,314	33,571	11.48	3,901,112	3,487,250	413,862	11.87
11	LANDFILL GAS	1,982	2,166	(184)	(8.49)	23,087	24,200	(1,113)	(4.60)
12	OIL - C.T.	(7)	0	(7)	100.00	695	96	599	823.96
13	TOTAL (MWH)	602,668	516,951	85,717	16.58	7,803,650	9,554,664	(1,751,014)	(18.33)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	841	572	269	47.03	13,694	5,307	8,387	158.03
15	COAL (TONS)	136,779	106,497	30,282	28.43	1,862,158	2,853,207	(991,049)	(34.73)
16	GAS (MCF) (1)	2,290,907	1,966,148	324,759	16.52	28,526,676	24,054,652	4,472,024	18.59
17	OIL - C.T. (BBL)	0	0	0	0.00	2,125	231	1,894	819.91
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,999,843	3,303,507	(303,664)	(9.19)	44,108,833	70,554,882	(26,446,049)	(37.48)
19	GAS - Generation (1)	2,311,588	2,025,133	286,455	14.14	27,869,741	24,776,291	3,093,450	12.49
20	OIL - C.T.	0	0	0	0.00	12,390	1,350	11,040	817.78
21	TOTAL (MMBTU)	5,311,431	5,328,640	(17,209)	(0.32)	71,990,964	95,332,523	(23,341,559)	(24.48)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	45.60	43.04	2.56	5.95	49.70	63.25	(13.55)	(21.42)
24	GAS	54.07	56.54	(2.47)	(4.37)	49.99	36.50	13.49	36.96
25	LANDFILL GAS	0.33	0.42	(0.09)	(21.43)	0.30	0.25	0.05	20.00
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	131.28	118.26	13.02	11.01	128.21	126.47	1.74	1.38
29	COAL ($/TON)	104.88	113.63	(8.75)	(7.70)	107.84	105.48	2.36	2.24
30	GAS ($/MCF) (1)	4.35	3.53	0.82	23.23	3.71	4.41	(0.70)	(15.87)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	104.14	105.13	(0.99)	(0.94)
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.84	3.68	1.16	31.52	4.66	4.28	0.38	8.88
33	GAS - Generation (1)	4.28	3.43	0.85	24.78	3.69	4.28	(0.59)	(13.79)
34	OIL - C.T.	0.00	0.00	0.00	0.00	17.86	17.99	(0.13)	(0.72)
35	TOTAL ($/MMBTU)	4.60	3.59	1.01	28.13	4.29	4.28	0.01	0.23
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,916	14,849	(3,933)	(26.49)	11,372	11,675	(303)	(2.60)
37	GAS - Generation (1)	7,238	7,062	176	2.49	7,296	7,203	93	1.29
38	OIL - C.T.	0	0	0	0.00	17,827	14,063	3,764	26.77
39	TOTAL (BTU/KWH)	8,939	10,464	(1,525)	(14.57)	9,351	10,053	(702)	(6.98)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.28	5.47	(0.19)	(3.47)	5.30	4.99	0.31	6.21
41	GAS	3.10	2.45	0.65	26.53	2.70	3.10	(0.40)	(12.90)
42	LANDFILL GAS	2.90	2.59	0.31	11.97	2.89	2.59	0.30	11.58
43	OIL - C.T.	0.00	0.00	0.00	0.00	31.84	25.30	6.54	25.85
44	TOTAL (¢/KWH)	4.10	3.75	0.35	9.33	4.00	4.30	(0.30)	(6.98)

Note. (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/GaL)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	20,893	51.3	100.0	86.6	11,774	Coal	10,325	11,913	245,993	1,060,182	5.07	102.68
2				6,835					Gas-G	79,898	1,017	81,256	371,336	5.43	4.65
3									Gas-S	1,603	1,017	1,630	7,450		4.65
4									Oil-S	140	138,572	816	16,846		120.33
5	Crist 5		75	11,382	23.6	98.4	50.8	11,769	Coal	5,649	11,856	133,954	580,093	5.10	102.69
6				1,364					Gas-G	15,874	1,017	16,143	73,775	5.41	4.65
7									Gas-S	543	1,017	552	2,523		4.65
8									Oil-S	33	138,572	194	4,008		121.45
9	Crist 6		291	95,832	46.6	74.8	60.4	10,879	Coal	43,765	11,911	1,042,558	4,493,976	4.69	102.68
10				2,026					Gas-G	21,910	1,017	22,283	101,830	5.03	4.65
11									Gas-S	9,438	1,017	9,597	43,856		4.65
12									Oil-S	15	138,572	85	1,747		116.47
13	Crist 7		485	(750)	(0.2)	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
14				0					Gas-G	0	1,017	0	0	0.00	0.00
15									Gas-S	0	1,017	0	0		0.00
16									Oil-S	0	138,572	0	0		0.00
17	Scholz 1		46	(235)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(161)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	30,906	26.5	95.4	44.2	10,840	Coal	13,906	12,046	335,034	1,545,558	5.00	111.14
22									Oil-S	469	140,277	2,764	62,686		133.66
23	Smith 2		195	34,164	24.3	100.0	37.4	11,045	Coal	15,786	11,952	377,338	1,754,400	5.14	111.14
24									Oil-S	25	140,277	146	3,318		132.72
25	Smith 3		558	309,136	76.8	86.2	93.5	7,090	Gas-G	2,161,643	1,014	2,191,906	9,353,348	3.03	4.33
26	Smith A	(2)	36	(7)	(0.0)	100.0	0.0	0	Oil	0	139,890	0	0	0.00	0.00
27	Other Generation			6,524									213,108	3.27	0.00
28	Perdido			1,982					Landfill Gas				57,409	2.90	0.00
29	Daniel 1	(1)	255	83,541	45.4	81.8	72.7	10,154	Coal	47,349	8,957	848,248	4,915,245	5.88	103.81
30									Oil-S	159	140,334	934	21,799		137.10
31	Daniel 2	(1)	255	(764)	(0.4)	83.2	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	140,334	0	5		0.00
33	Total		2,459	602,668	34.0	70.9	45.4	8,939				5,311,431	24,684,498	4.10	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
	Recoverable Fuel	24,680,439	4.10

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	535	1,318	(783)	(59.41)	14,624	16,389	(1,765)	(10.77)
3	UNIT COST ($/BBL)	132.05	118.10	13.95	11.81	132.10	125.76	6.34	5.04
4	AMOUNT ($)	70,649	155,659	(85,010)	(54.61)	1,931,779	2,081,029	(129,250)	(6.27)
5	*BURNED:*								
6	UNITS (BBL)	874	572	302	52.80	14,147	5,308	8,839	166.52
7	UNIT COST ($/BBL)	131.37	118.26	13.11	11.09	128.36	126.45	1.91	1.51
8	AMOUNT ($)	114,819	67,646	47,173	69.74	1,815,938	671,213	1,144,725	170.55
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,865	12,038	(6,173)	(51.28)	5,865	12,038	(6,173)	(51.28)
11	UNIT COST ($/BBL)	128.73	118.66	10.07	8.49	128.73	118.66	10.07	8.49
12	AMOUNT ($)	754,998	1,428,405	(673,407)	(47.14)	754,998	1,428,405	(673,407)	(47.14)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	161,782	164,700	(2,918)	(1.77)	1,867,494	2,595,266	(727,772)	(28.04)
16	UNIT COST ($/TON)	107.01	120.89	(13.88)	(11.48)	107.25	110.63	(3.38)	(3.06)
17	AMOUNT ($)	17,312,745	19,909,908	(2,597,163)	(13.04)	200,268,622	287,101,657	(86,813,035)	(30.24)
18	*BURNED:*								
19	UNITS (TONS)	136,779	106,497	30,282	28.43	1,862,158	2,853,207	(991,049)	(34.73)
20	UNIT COST ($/TON)	104.91	113.63	(8.72)	(7.67)	107.29	105.48	1.81	1.72
21	AMOUNT ($)	14,349,453	12,101,319	2,248,134	18.58	199,788,702	300,965,860	(101,177,158)	(33.62)
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	906,683	957,408	(50,725)	(5.30)	906,683	957,408	(50,725)	(5.30)
24	UNIT COST ($/TON)	104.47	118.93	(14.46)	(12.16)	104.47	118.93	(14.46)	(12.16)
25	AMOUNT ($)	94,723,759	113,860,738	(19,136,979)	(16.81)	94,723,759	113,860,738	(19,136,979)	(16.81)
26	DAYS SUPPLY	43	45	(2)	(4.44)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,225,715	2,025,133	200,582	9.90	28,576,696	24,776,291	3,800,405	15.34
29	UNIT COST ($/MMBTU)	4.16	3.45	0.71	20.58	3.67	4.34	(0.67)	(15.44)
30	AMOUNT ($)	9,252,639	6,996,744	2,255,895	32.24	104,759,060	107,646,908	(2,887,848)	(2.68)
31	*BURNED:*								
32	UNITS (MMBTU)	2,323,367	2,025,133	298,234	14.73	28,934,310	24,776,291	4,158,019	16.78
33	UNIT COST ($/MMBTU)	4.28	3.45	0.83	24.06	3.65	4.34	(0.69)	(15.90)
34	AMOUNT ($)	9,954,118	6,996,744	2,957,374	42.27	105,749,565	107,646,908	(1,897,343)	(1.76)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	671,964	0	671,964	100.00	671,964	0	671,964	100.00
37	UNIT COST ($/MMBTU)	4.27	0.00	4.27	100.00	4.27	0.00	4.27	100.00
38	AMOUNT ($)	2,867,419	0	2,867,419	100.00	2,867,419	0	2,867,419	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	1,418	767	651	84.88
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	135.30	118.27	17.00	14.37
42	AMOUNT ($)	0	0	0	0.00	191,849	90,715	101,134	111.49
43	*BURNED:*								
44	UNITS (BBL)	0	0	0	0.00	2,125	231	1,894	819.91
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	104.14	105.13	(0.99)	(0.94)
46	AMOUNT ($)	0	0	0	0.00	221,292	24,285	197,007	811.23
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,120	7,058	(938)	(13.29)	6,120	7,058	(938)	(13.29)
49	UNIT COST ($/BBL)	106.69	104.99	1.70	1.62	106.69	104.99	1.70	1.62
50	AMOUNT ($)	652,952	741,007	(88,055)	(11.88)	652,952	741,007	(88,055)	(11.88)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (8)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		135,080,000	0	135,080,000	2.15	2.47	2,899,000	3,342,000
2	Various	Economy Sales	8,185,000	0	8,185,000	2.32	2.68	190,000	219,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	29,000	29,000
4	TOTAL ESTIMATED SALES		143,265,000	0	143,265,000	2.18	2.51	3,118,000	3,590,000
	ACTUAL								
5	Southern Company Interchange		364,088,137	0	364,088,137	2.90	3.17	10,575,429	11,534,216
6	A.E.C.	External	211,234	0	211,234	3.10	4.28	6,549	9,046
7	AECI	External	69,215	0	69,215	2.72	4.17	1,879	2,887
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	104,000	0	104,000	3.48	3.30	3,622	3,432
13	CARGILE	External	1,850,790	0	1,850,790	2.92	3.37	54,063	62,387
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	767,700	0	767,700	2.79	3.16	21,456	24,288
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	63,370	0	63,370	(1.89)	6.07	(1,201)	3,849
19	EAGLE EN	External	245,491	0	245,491	2.94	4.07	7,213	10,002
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	9,749	0	9,749	3.55	4.80	346	486
22	ENTERGY	External	0	0	0	0.00	0.00	338	0
23	FPC	External	6,435	0	6,435	59.63	3.40	3,850	219
24	FPL	External	0	0	0	0.00	0.00	(7)	0
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	338,962	0	338,962	2.56	3.09	8,676	10,475
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	981,502	0	981,502	2.79	3.13	27,344	30,721
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	738,979	0	738,979	3.12	3.50	23,080	25,866
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	660,437	0	660,437	3.00	3.40	19,811	22,485
36	ORLANDO	External	0	0	0	0.00	0.00	0	0
37	PJM	External	796,486	0	796,486	3.36	4.20	26,767	33,413
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	1,538,710	0	1,538,710	3.24	3.85	49,930	59,239
40	SEC	External	115,951	0	115,951	2.63	3.25	3,047	3,765
41	SEPA	External	1,859,820	0	1,859,820	2.66	3.40	49,465	63,244
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	13,000	0	13,000	2.60	4.50	338	585
44	TEA	External	2,099,770	0	2,099,770	2.98	3.84	62,536	80,533
45	TECD	External	0	0	0	0.00	0.00	0	0
46	TENASKA	External	0	0	0	0.00	0.00	0	0
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	0	0	0	0.00	0.00	(8)	0
49	UPP	External	0	0	0	0.00	0.00	0	0
50	WRI	External	92,040	0	92,040	2.87	3.15	2,645	2,898
51	Less: Flow-Thru Energy		(12,528,602)	0	(12,528,602)	2.93	2.93	(367,589)	(367,589)
52	SEPA		827,640	827,640	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	25,477	25,477
54	Other transactions including adj.		145,234,828	127,661,413	17,573,215	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		510,185,244	128,489,053	381,696,191	2.08	2.28	10,605,056	11,616,448
56	Difference in Amount		366,920,244	128,489,053	238,431,191	(0.10)	(0.23)	7,487,056	8,026,448
57	Difference in Percent		256.11	0.00	166.43	(4.59)	(9.16)	240.12	223.58

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

			PERIOD TO DATE						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢/KWH FUEL COST	(b) ¢/KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,122,358,000	0	1,122,358,000	3.15	3.53	35,341,000	39,630,000
2	Various	Economy Sales	105,935,000	0	105,935,000	3.47	3.88	3,677,000	4,112,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	619,000	241,000
4	TOTAL ESTIMATED SALES		1,228,293,000	0	1,228,293,000	3.23	3.58	39,637,000	43,983,000
	ACTUAL								
5	Southern Company Interchange		3,978,271,723	0	3,978,271,723	2.57	2.80	102,244,449	111,507,191
6	A.E.C.	External	4,275,192	0	4,275,192	2.79	3.52	119,323	150,491
7	AECI	External	142,854	0	142,854	2.50	3.84	3,589	5,485
8	AEP	External	8,304	0	8,304	3.40	5.50	214	347
9	AMERENEM	External	23,592	0	23,592	0.00	4.10	0	967
10	ARCLIGHT	External	22,685	0	22,685	6.98	4.92	1,584	1,117
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	777,380	0	777,380	2.76	3.47	21,489	27,001
13	CARGILE	External	5,739,275	0	5,739,275	2.73	3.17	156,897	182,053
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	2,036,684	0	2,036,684	2.58	3.02	52,579	61,602
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	4,814,902	0	4,814,902	2.26	3.37	108,840	162,318
19	EAGLE EN	External	1,747,489	0	1,747,489	2.54	3.50	44,459	61,141
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	123,353	0	123,353	2.46	4.01	3,030	4,952
22	ENTERGY	External	14,920,480	0	14,920,480	3.36	6.79	501,245	1,012,684
23	FPC	External	523,955	0	523,955	4.11	5.16	21,523	27,184
24	FPL	External	4,174,182	0	4,174,182	2.83	4.05	118,175	168,846
25	JARON	External	228,847	0	228,847	3.31	5.04	7,566	11,525
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	1,283,883	0	1,283,883	2.67	3.43	34,324	44,053
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	2,112,224	0	2,112,224	2.89	3.23	61,015	68,257
32	NCEMC	External	13,974	0	13,974	1.95	2.83	272	396
33	NCMPA1	External	1,021,850	0	1,021,850	2.95	3.35	30,094	34,239
34	NRG	External	75,066	0	75,066	3.68	5.03	2,763	3,776
35	OPC	External	2,150,453	0	2,150,453	2.61	3.33	56,062	71,675
36	ORLANDO	External	20,147	0	20,147	2.65	3.77	534	759
37	PJM	External	10,798,722	0	10,798,722	2.24	3.34	242,323	360,855
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	5,437,488	0	5,437,488	3.20	4.34	173,848	235,943
40	SEC	External	2,116,723	0	2,116,723	2.46	3.17	51,988	67,049
41	SEPA	External	8,466,799	0	8,466,799	2.40	3.00	203,208	254,349
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	2,410,915	0	2,410,915	3.31	4.48	79,837	108,043
44	TEA	External	10,919,504	0	10,919,504	2.38	3.26	259,807	355,626
45	TECO	External	411,994	0	411,994	2.53	3.84	10,407	15,820
46	TENASKA	External	30,742	0	30,742	3.11	4.37	957	1,342
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	1,046,170	0	1,046,170	2.61	3.81	27,272	39,895
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	288,337	0	286,337	2.70	3.39	7,797	9,778
51	Less: Flow-Thru Energy		(87,974,481)	0	(87,974,481)	2.70	2.70	(2,372,948)	(2,372,948)
52	SEPA		12,271,334	12,271,334	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	520,387	520,387
54	Other transactions including adj.		2,424,475,022	1,882,494,758	561,980,264	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		6,415,354,682	1,874,766,092	4,540,588,590	1.60	1.76	102,797,327	112,686,879
56	Difference in Amount		5,187,061,682	1,874,766,092	3,312,295,590	(1.63)	(1.82)	63,160,327	68,703,879
57	Difference in Percent		422.30	0.00	269.67	(50.46)	(50.84)	159.35	156.21

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: NOVEMBER 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 188 of 209

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

CURRENT MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
5 Ascend Performance Materials	COG 1	17,596,000	0	0	0	3.12	3.12	549,438
6 International Paper	COG 1	63,000	0	0	0	3.69	3.69	2,326
7 TOTAL		17,659,000	0	0	0	3.12	3.12	551,763

PERIOD-TO-DATE

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢/KWH		(8)
PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	52
5 Ascend Performance Materials	COG 1	189,584,000	0	0	0	2.78	2.78	5,272,199
6 International Paper	COG 1	981,000	0	0	0	2.86	2.86	28,058
7 TOTAL		194,791,000	0	0	0	2.88	2.88	5,617,381

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2012

	(1)	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	PURCHASED FROM						
	ESTIMATED						
1	Southern Company Interchange	57,522,000	2.51	1,441,000	1,068,867,000	3.70	39,550,000
2	Economy Energy	7,888,000	2.67	211,000	53,750,000	3.78	2,030,000
3	Other Purchases	374,337,000	2.64	9,890,000	2,177,073,000	2.39	52,012,000
4	TOTAL ESTIMATED PURCHASES	439,747,000	2.62	11,542,000	3,299,690,000	2.84	93,592,000
	ACTUAL						
5	Southern Company Interchange	112,181,156	3.10	3,478,397	866,655,298	2.78	24,104,751
6	Non-Associated Companies	38,271,853	0.58	220,558	337,403,752	(0.69)	(2,327,044)
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	430,091,000	3.38	14,551,059	5,716,891,000	2.52	143,799,092
9	Other Wheeled Energy	43,497,000	0.00	N/A	842,483,000	0.00	N/A
10	Other Transactions	73,754,071	0.02	17,291	1,469,014,461	0.02	293,375
11	Less: Flow-Thru Energy	(12,528,602)	3.15	(394,913)	(87,974,481)	2.95	(2,597,512)
12	TOTAL ACTUAL PURCHASES	685,266,478	2.61	17,872,392	9,144,473,030	1.79	163,272,662
13	Difference in Amount	245,519,478	(0.01)	6,330,392	5,844,783,030	(1.05)	69,680,662
14	Difference in Percent	55.83	(0.38)	54.85	177.13	(36.97)	74.45

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 190 of 209

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.8	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692	0	0	1,227,853
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,853
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					$ 2,379,394		$ 1,733,195		$ 1,750,407		$ 1,484,274		$ 2,071,953		$ 7,640,423	$ 17,059,846

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	TERM End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	0	0	0	0	57	371,149	(116.5)	(84,799)	165.6	63,041			1,577,044
SUBTOTAL					$ -		$ -		$ 371,149		$ (84,799)		$ 63,041		$ -	$ 1,577,044
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	8,286,469	Varies	7,144,681	Varies	6,755,384	Varies	1,978,232	Varies	1,978,232			41,985,111
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(5,502)	Varies	(8,183)	Varies	(3,883)	Varies	(3,087)	Varies	(4,884)			(55,459)
SUBTOTAL					$ 8,280,967		$ 7,136,698		$ 6,751,501		$ 1,975,145		$ 1,973,348		$ -	$ 41,929,652
TOTAL					$ 8,280,967		$ 7,136,698		$ 7,122,650		$ 1,890,346		$ 2,036,389		$ -	$ 43,506,696

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 130001-EI

MONTHLY FUEL FILING

DECEMBER 2012

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2012
CURRENT MONTH

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	22,173,336	25,049,369	(2,876,033)	(11.48)	587,285,000	666,688,000	(79,403,000)	(11.91)	3.7756	3.7573	0.02	0.49
2	Hedging Settlement Costs (A2)	1,965,204	1,783,760	181,444	10.17	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	4,262	0	4,262	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	24,142,802	26,833,129	(2,690,327)	(10.03)	587,285,000	666,688,000	(79,403,000)	(11.91)	4.1109	4.0248	0.09	2.14
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	19,609,191	15,116,000	4,493,191	29.72	765,964,043	529,819,000	236,145,043	44.57	2.5601	2.8530	(0.29)	(10.27)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	706,746	0	706,746	100.00	24,056,000	0	24,056,000	100.00	2.9379	0.0000	2.94	0.00
12	TOTAL COST OF PURCHASED POWER	20,315,937	15,116,000	5,199,937	34.40	790,020,043	529,819,000	260,201,043	49.11	2.5716	2.8530	(0.28)	(9.86)
13	Total Available MWH (Line 5 + Line 12)	44,458,739	41,949,129	2,509,610	5.98	1,377,305,043	1,196,507,000	180,798,043	15.11				
14	Fuel Cost of Economy Sales (A6)	(113,987)	(224,000)	110,013	(49.11)	(4,266,291)	(8,911,000)	4,644,709	(52.12)	(2.6718)	(2.5137)	(0.16)	(6.29)
15	Gain on Economy Sales (A6)	801	(42,000)	42,801	(101.91)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(11,005,277)	(5,846,000)	(5,159,277)	88.25	(516,237,394)	(242,000,000)	(274,237,394)	113.32	(2.1318)	(2.4157)	0.28	11.75
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(11,118,463)	(6,112,000)	(5,006,463)	81.91	(520,503,685)	(250,911,000)	(269,592,685)	107.45	(2.1361)	(2.4359)	0.30	12.31
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	33,340,276	35,837,129	(2,496,853)	(6.97)	856,801,358	945,596,000	(88,794,642)	(9.39)	3.8912	3.7899	0.10	2.67
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	65,848	70,189	(4,341)	(6.18)	1,692,218	1,852,000	(159,782)	(8.63)	3.8912	3.7899	0.10	2.67
22	T & D Losses *	1,745,385	1,827,603	(82,218)	(4.50)	44,854,681	48,223,000	(3,368,319)	(6.98)	3.8912	3.7899	0.10	2.67
23	TERRITORIAL KWH SALES	33,340,276	35,837,129	(2,496,853)	(6.97)	810,254,459	895,521,000	(85,266,541)	(9.52)	4.1148	4.0018	0.11	2.82
24	Wholesale KWH Sales	1,057,254	1,243,548	(186,294)	(14.98)	25,693,660	31,075,000	(5,381,340)	(17.32)	4.1148	4.0018	0.11	2.82
25	Jurisdictional KWH Sales	32,283,022	34,593,581	(2,310,559)	(6.68)	784,560,799	864,446,000	(79,885,201)	(9.24)	4.1148	4.0018	0.11	2.82
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	32,331,447	34,645,471	(2,314,024)	(6.68)	784,560,799	864,446,000	(79,885,201)	(9.24)	4.1210	4.0078	0.11	2.82
28	TRUE-UP	(7,617,648)	(7,617,648)	0	0.00	784,560,799	864,446,000	(79,885,201)	(9.24)	(0.9709)	(0.8812)	(0.09)	10.18
29	TOTAL JURISDICTIONAL FUEL COST	24,713,799	27,027,823	(2,314,024)	(8.56)	784,560,799	864,446,000	(79,885,201)	(9.24)	3.1501	3.1266	0.02	0.75
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.1524	3.1289	0.02	0.75
32	GPIF Reward / (Penalty)	53,793	53,793	0	0.00	784,560,799	864,446,000	(79,885,201)	(9.24)	0.0069	0.0062	0.00	11.29
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.1593	3.1351	0.02	0.77
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.159	3.135		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: DECEMBER 2012

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 22,173,336
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	4,262
4	Hedging Settlement Costs	Schedule A-2, Line A-5	1,965,204
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	19,609,191
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	706,746
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(11,118,463)
10	Total Fuel and Net Power Transactions		$ 33,340,276

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2012
PERIOD TO DATE

		DOLLARS				KWH				CENTS/KWH			
				DIFFERENCE				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%	ACTUAL	EST'd	AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	334,006,797	435,601,965	(101,595,168)	(23.32)	8,390,935,000	10,221,352,000	(1,830,417,000)	(17.91)	3.9806	4.2617	(0.28)	(6.60)
2	Hedging Settlement Costs (A2)	32,865,554	18,441,340	14,424,214	78.22	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	175,523	0	175,523	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	367,047,874	454,043,305	(86,995,431)	(19.16)	8,390,935,000	10,221,352,000	(1,830,417,000)	(17.91)	4.3743	4.4421	(0.07)	(1.53)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	182,881,852	108,708,000	74,173,852	68.23	9,910,437,073	3,829,509,000	6,080,928,073	158.79	1.8453	2.8387	(0.99)	(34.99)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	6,324,127	0	6,324,127	100.00	218,847,000	0	218,847,000	100.00	2.8897	0.0000	2.89	0.00
12	TOTAL COST OF PURCHASED POWER	189,205,979	108,708,000	80,497,979	74.05	10,129,284,073	3,829,509,000	6,299,775,073	164.51	1.8679	2.8387	(0.97)	(34.20)
13	Total Available MWH (Line 5 + Line 12)	556,253,853	562,751,305	(6,497,452)	(1.15)	18,520,219,073	14,050,861,000	4,469,358,073	31.81				
14	Fuel Cost of Economy Sales (A6)	(2,519,426)	(3,901,000)	1,381,574	(35.42)	(92,577,375)	(114,846,000)	22,268,625	(19.39)	(2.7214)	(3.3967)	0.68	19.88
15	Gain on Economy Sales (A6)	(519,587)	(661,000)	141,413	(21.39)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(110,876,776)	(41,187,000)	(69,689,776)	169.20	(6,843,280,992)	(1,364,358,000)	(5,478,922,992)	401.58	(1.6202)	(3.0188)	1.40	46.33
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(113,915,789)	(45,749,000)	(68,166,789)	149.00	(6,935,858,367)	(1,479,204,000)	(5,456,654,367)	368.89	(1.6424)	(3.0928)	1.45	46.90
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	442,338,064	517,002,305	(74,664,241)	(14.44)	11,584,360,706	12,571,657,000	(987,296,294)	(7.85)	3.8184	4.1124	(0.29)	(7.15)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	762,372	897,202	(134,830)	(15.03)	19,965,754	21,817,000	(1,851,246)	(8.49)	3.8184	4.1124	(0.29)	(7.15)
22	T & D Losses *	22,015,642	28,898,411	(6,882,769)	(23.82)	576,567,197	702,714,000	(126,146,803)	(17.95)	3.8184	4.1124	(0.29)	(7.15)
23	TERRITORIAL KWH SALES	442,338,064	517,002,305	(74,664,241)	(14.44)	10,987,827,755	11,847,126,000	(859,298,245)	(7.25)	4.0257	4.3639	(0.34)	(7.75)
24	Wholesale KWH Sales	13,097,414	16,818,864	(3,721,450)	(22.13)	325,194,179	384,391,000	(59,196,821)	(15.40)	4.0276	4.3755	(0.35)	(7.95)
25	Jurisdictional KWH Sales	429,240,650	500,183,441	(70,942,791)	(14.18)	10,662,633,576	11,462,735,000	(800,101,424)	(6.98)	4.0257	4.3636	(0.34)	(7.74)
26	Jurisdictional Loss Multiplier***	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	429,813,850	500,716,362	(70,902,512)	(14.16)	10,662,633,576	11,462,735,000	(800,101,424)	(6.98)	4.0310	4.3682	(0.34)	(7.72)
28	TRUE-UP	(49,663,841)	(49,663,841)	0	0.00	10,662,633,576	11,462,735,000	(800,101,424)	(6.98)	(0.4658)	(0.4333)	(0.03)	7.50
29	TOTAL JURISDICTIONAL FUEL COST	380,150,009	451,052,521	(70,902,512)	(15.72)	10,662,633,576	11,462,735,000	(800,101,424)	(6.98)	3.5652	3.9349	(0.37)	(9.40)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.5678	3.9377	(0.37)	(9.39)
32	GPIF Reward / (Penalty)	645,511	645,511	0	0.00	10,662,633,576	11,462,735,000	(800,101,424)	(6.98)	0.0061	0.0056	0.00	8.93
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5739	3.9433	(0.37)	(9.37)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.574	3.943		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
***Jurisdictional Loss Multiplier Jan-Mar is 1.0007 and Apr-Dec 1.0015

4

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	21,959,688.21	24,956,891	(2,997,202.79)	(12.01)	331,177,012.44	433,603,453	(102,426,440.64)	(23.62)
1a	Other Generation	213,647.44	92,478	121,169.44	131.03	2,829,784.58	1,998,512	831,272.58	41.59
2	Fuel Cost of Power Sold	(11,118,462.58)	(6,112,000)	(5,006,462.58)	(81.91)	(113,915,789.16)	(45,749,000)	(68,166,789.16)	(149.00)
3	Fuel Cost - Purchased Power	19,609,190.77	15,116,000	4,493,190.77	29.72	182,881,852.04	108,708,000	74,173,852.04	68.23
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	0.00	0.00	0	0.00	0.00
3b	Energy Payments to Qualifying Facilities	706,746.08	0	706,746.08	100.00	6,324,126.90	0	6,324,126.90	100.00
4	Energy Cost - Economy Purchases	0.00	0	0.00	0.00	0.00	0	0.00	0.00
5	Hedging Settlement Cost	1,965,204.00	1,783,760	181,444.00	10.17	32,865,554.00	18,441,340	14,424,214.00	78.22
6	Total Fuel & Net Power Transactions	33,336,013.92	35,837,129	(2,501,115.08)	(6.98)	442,162,540.80	517,002,305	(74,839,764.28)	(14.48)
7	AdjustmentsTo Fuel Cost*	4,262.37	0	4,262.37	100.00	175,523.25	0	175,523.25	100.00
8	Adj. Total Fuel & Net Power Transactions	33,340,276.29	35,837,129	(2,496,852.71)	(6.97)	442,338,064.05	517,002,305	(74,664,241.03)	(14.44)
B.	*KWH Sales*								
1	Jurisdictional Sales	784,560,799	864,446,000	(79,885,201)	(9.24)	10,662,633,576	11,462,735,000	(800,101,424)	(6.98)
2	Non-Jurisdictional Sales	25,693,660	31,075,000	(5,381,340)	(17.32)	325,194,179	384,391,000	(59,196,821)	(15.40)
3	Total Territorial Sales	810,254,459	895,521,000	(85,266,541)	(9.52)	10,987,827,755	11,847,126,000	(859,298,245)	(7.25)
4	Juris. Sales as % of Total Terr. Sales	96.8289	96.5300	0.2989	0.31	97.0404	96.7554	0.2850	0.29

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
			$ DIFFERENCE				$ DIFFERENCE		
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	29,175,742.62	31,509,057	(2,333,314.08)	(7.41)	437,599,847.24	477,860,350	(40,260,502.80)	(8.43)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	7,617,648.00	7,617,648	0.00	0.00	49,663,840.76	49,663,841	0.00	0.00
2b	Incentive Provision	(53,753.89)	(53,754)	0.00	0.00	(645,046.57)	(645,047)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	36,739,636.73	39,072,951	(2,333,314.27)	(5.97)	486,618,641.43	526,879,144	(40,260,502.57)	(7.64)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	33,340,276.29	35,837,129	(2,496,852.71)	(6.97)	442,338,064.05	517,002,305	(74,664,240.95)	(14.44)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.8289	96.5300	0.2989	0.31	97.0404	96.7554	0.2850	0.29
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	32,331,447.32	34,645,471	(2,314,023.68)	(6.68)	429,813,850.72	500,716,362	(70,902,511.28)	(14.16)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	4,408,189.41	4,427,480	(19,290.59)	0.44	56,804,790.71	26,162,783	30,642,007.71	(117.12)
8	Interest Provision for the Month	1,645.14	(2,990)	4,635.14	155.02	33,964.49	(24,777)	58,741.49	237.08
9	Beginning True-Up & Interest Provision	20,299,536.59	(32,383,862)	52,683,398.59	162.68	9,928,693.69	(12,051,185)	21,979,878.69	182.39
10	True-Up Collected / (Refunded)	(7,617,648.00)	(7,617,648)	0.00	0.00	(49,663,840.76)	(49,663,841)	0.00	0.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	17,091,723.14	(35,577,020)	52,668,743.14	148.04	17,103,608.13	(35,577,020)	52,680,628.13	148.07
12	Adjustment*	0.00	0	0.00	0.00	(11,884.99)	0	(11,884.99)	100.00
13	End of Period - Total Net True-Up	17,091,723.14	(35,577,020)	52,668,743.14	148.04	17,091,723.14	(35,577,020)	52,668,743.14	148.04

**Interest associated with coal transportation costs that were understated January - May and corrected in June.*

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	**ESTIMATED**	**AMOUNT ($)**	**%**
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	20,299,536.59	(32,383,862)	52,683,398.59	(162.68)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	17,090,078.00	(35,574,030)	52,664,108.00	(148.04)
3	Total of Beginning & Ending True-Up Amts.	37,389,614.59	(67,957,892)	105,347,506.59	(155.02)
4	Average True-Up Amount	18,694,807.30	(33,978,946)	52,673,753.30	(155.02)
5	Interest Rate 1st Day of Reporting Business Month	0.16	0.16	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.05	0.05	0.0000	
7	Total (D5+D6)	0.21	0.21	0.0000	
8	Annual Average Interest Rate	0.11	0.11	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0088	0.0088	0.0000	
10	Interest Provision (D4*D9)	1,645.14	(2,990)	4,635.14	(155.02)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	(18,005)	67,626	(85,631)	(126.62)	1,737,641	738,839	998,802	135.19
2	COAL	12,384,394	14,643,709	(2,259,315)	(15.43)	213,207,290	315,609,570	(102,402,280)	(32.45)
3	GAS	9,626,622	10,279,928	(653,306)	(6.36)	115,036,807	118,543,416	(3,506,609)	(2.96)
4	GAS (B.L.)	99,073	0	99,073	100.00	3,054,589	-	3,054,589	100.00
5	LANDFILL GAS	63,614	58,106	5,508	9.48	731,540	685,856	45,684	6.66
6	OIL - C.T.	17,638	0	17,638	100.00	238,930	24,285	214,645	883.86
7	TOTAL ($)	22,173,336	25,049,369	(2,876,033)	(11.48)	334,006,797	435,601,965	(101,595,168)	(23.32)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	255,580	267,177	(11,597)	(4.34)	4,134,336	6,310,295	(2,175,959)	(34.48)
10	GAS	329,529	397,271	(67,742)	(17.05)	4,230,641	3,884,521	346,120	8.91
11	LANDFILL GAS	2,153	2,240	(87)	(3.88)	25,240	26,440	(1,200)	(4.54)
12	OIL - C.T.	23	0	23	100.00	718	96	622	647.92
13	TOTAL (MWH)	587,285	666,688	(79,403)	(11.91)	8,390,935	10,221,352	(1,830,417)	(17.91)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	(45)	572	(617)	(107.87)	13,649	5,879	7,770	132.16
15	COAL (TONS)	119,643	129,326	(9,683)	(7.49)	1,981,801	2,982,533	(1,000,732)	(33.55)
16	GAS (MCF) (1)	2,343,512	2,684,087	(340,575)	(12.69)	30,870,188	26,738,739	4,131,449	15.45
17	OIL - C.T. (BBL)	165	0	165	100.00	2,290	231	2,059	891.34
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,892,802	4,262,698	(1,369,896)	(32.14)	47,001,635	74,817,580	(27,815,945)	(37.18)
19	GAS - Generation (1)	2,354,136	2,764,610	(410,474)	(14.85)	30,223,877	27,540,901	2,682,976	9.74
20	OIL - C.T.	544	0	544	100.00	12,934	1,350	11,584	858.07
21	TOTAL (MMBTU)	5,247,482	7,027,308	(1,779,826)	(25.33)	77,238,446	102,359,831	(25,121,385)	(24.54)
	GENERATION MIX (% MWH)								
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	43.52	40.08	3.44	8.58	49.27	61.74	(12.47)	(20.20)
24	GAS	56.11	59.58	(3.47)	(5.82)	50.42	38.00	12.42	32.68
25	LANDFILL GAS	0.37	0.34	0.03	8.82	0.30	0.26	0.04	15.38
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.01	0.00	0.01	100.00
27	TOTAL (% MWH)	100.00	100.00	0.00	0.00	100.00	100.00	0.00	0.00
	FUEL COST ($) / UNIT								
28	LIGHTER OIL ($/BBL)	400.11	118.23	281.88	238.42	127.31	125.67	1.64	1.31
29	COAL ($/TON)	103.51	113.23	(9.72)	(8.58)	107.58	105.82	1.76	1.66
30	GAS ($/MCF) (1)	4.06	3.79	0.27	7.12	3.73	4.35	(0.62)	(14.25)
31	OIL - C.T. ($/BBL)	106.90	0.00	106.90	100.00	104.34	105.13	(0.79)	(0.75)
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.31	3.45	0.86	24.93	4.64	4.23	0.41	9.69
33	GAS - Generation (1)	4.00	3.68	0.32	8.70	3.71	4.22	(0.51)	(12.09)
34	OIL - C.T.	32.42	0.00	32.42	100.00	18.47	17.99	0.48	2.67
35	TOTAL ($/MMBTU)	4.17	3.54	0.63	17.80	4.28	4.23	0.05	1.18
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,319	15,955	(4,636)	(29.06)	11,369	11,856	(487)	(4.11)
37	GAS - Generation (1)	7,292	7,009	283	4.04	7,296	7,184	112	1.56
38	OIL - C.T.	23,652	0	23,652	100.00	18,014	14,063	3,951	28.10
39	TOTAL (BTU/KWH)	9,072	10,622	(1,550)	(14.59)	9,331	10,090	(759)	(7.52)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.88	5.51	(0.63)	(11.43)	5.27	5.01	0.26	5.19
41	GAS	2.92	2.59	0.33	12.74	2.72	3.05	(0.33)	(10.82)
42	LANDFILL GAS	2.95	2.59	0.36	13.90	2.90	2.59	0.31	11.97
43	OIL - C.T.	76.69	0.00	76.69	100.00	33.28	25.30	7.98	31.54
44	TOTAL (¢/KWH)	3.78	3.76	0.02	0.53	3.98	4.26	(0.28)	(6.57)

Note: (1) Calculations for Line 16, 19, 30, 33, and 37 exclude Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE A-4

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2012	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	31,543	71.8	100.0	71.8	11,197	Coal	14,902	11,851	353,197	1,517,422	4.81	101.83
2				8,507					Gas-G	94,107	1,012	95,237	391,356	4.60	4.16
3									Gas-S	0	1,012	0	0		0.00
4									Oil-S	3	138,572	18	366		122.00
5	Crist 5		75	(669)	(1.2)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				-					Gas-G	0	1,012	0	0	0.00	0.00
7									Gas-S	0	1,012	0	0		0.00
8									Oil-S	0	138,572	0	0		0.00
9	Crist 6		291	98,529	46.6	95.7	69.0	10,608	Coal	43,738	11,948	1,045,169	4,453,850	4.52	101.83
10				2,268					Gas-G	21,715	1,012	21,976	90,304	3.98	4.16
11									Gas-S	0	1,012	0	0		0.00
12									Oil-S	60	138,572	350	7,234		120.57
13	Crist 7		465	71,942	20.8	38.6	53.9	11,872	Coal	36,357	11,746	854,093	3,702,194	5.15	101.83
14				0					Gas-G	0	1,012	0	0	0.00	0.00
15									Gas-S	23,824	1,012	24,110	99,073		4.16
16									Oil-S	111	138,572	648	13,386		120.59
17	Scholz 1		46	(239)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(168)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	56,702	47.0	100.0	47.0	10,848	Coal	24,646	12,479	615,125	2,714,987	4.79	110.16
22									Oil-S	15	140,277	91	2,065		137.67
23	Smith 2		195	(278)	(0.2)	67.1	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	140,277	0	0		0.00
25	Smith 3		584	312,068	71.8	88.2	88.2	7,168	Gas-G	2,203,866	1,015	2,236,924	8,931,316	2.86	4.05
26	Smith A	(2)	40	23	0.1	100.0	59.5	23,652	Oil	165	139,890	544	9,877	42.94	59.86
27	Other Generation			6,686									213,647	3.20	0.00
28	Perdido			2,153					Landfill Gas				63,614	2.95	0.00
29	Daniel 1	(1)	255	(1,215)	(0.6)	75.3	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	139,339	0	0		0.00
31	Daniel 2	(1)	255	(567)	(0.3)	89.8	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	139,339	0	0		0.00
33	Total		2,489	587,285	31.7	79.1	45.0	9,072				5,247,482	22,210,691	3.78	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
(235)	Smith Inventory Adjustment - Oil	(33,296)	
	Recoverable Fuel	22,173,336	3.78

Docket No. 130001-EI
2012 Final True-Up Filing
Exhibit RWD-1, Page 201 of 209

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	307	1,339	(1,032)	(77.07)	14,931	17,728	(2,797)	(15.78)
3	UNIT COST ($/BBL)	133.74	118.10	15.64	13.24	132.13	125.18	6.95	5.55
4	AMOUNT ($)	41,057	158,134	(117,077)	(74.04)	1,972,836	2,219,163	(246,327)	(11.10)
5	*BURNED :*								
6	UNITS (BBL)	205	572	(367)	(64.16)	14,352	5,880	8,472	144.08
7	UNIT COST ($/BBL)	122.13	118.23	3.90	3.30	128.27	125.65	2.62	2.09
8	AMOUNT ($)	25,036	67,626	(42,590)	(62.98)	1,840,974	738,839	1,102,135	149.17
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,967	12,805	(6,838)	(53.40)	5,967	12,805	(6,838)	(53.40)
11	UNIT COST ($/BBL)	129.21	118.62	10.59	8.93	129.21	118.62	10.59	8.93
12	AMOUNT ($)	771,019	1,518,913	(747,894)	(49.24)	771,019	1,518,913	(747,894)	(49.24)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	151,167	169,604	(18,437)	(10.87)	2,018,661	2,764,870	(746,209)	(26.99)
16	UNIT COST ($/TON)	109.44	123.71	(14.27)	(11.54)	107.41	111.43	(4.02)	(3.61)
17	AMOUNT ($)	16,543,310	20,981,490	(4,438,180)	(21.15)	216,831,932	308,083,147	(91,251,215)	(29.62)
18	*BURNED :*								
19	UNITS (TONS)	119,643	129,326	(9,683)	(7.49)	1,981,801	2,982,533	(1,000,732)	(33.55)
20	UNIT COST ($/TON)	103.55	113.23	(9.68)	(8.55)	107.06	105.82	1.24	1.17
21	AMOUNT ($)	12,388,453	14,643,709	(2,255,256)	(15.40)	212,177,155	315,609,569	(103,432,414)	(32.77)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	938,207	997,686	(59,479)	(5.96)	938,207	997,686	(59,479)	(5.96)
24	UNIT COST ($/TON)	105.39	120.48	(15.09)	(12.52)	105.39	120.48	(15.09)	(12.52)
25	AMOUNT ($)	98,878,616	120,198,519	(21,319,903)	(17.74)	98,878,616	120,198,519	(21,319,903)	(17.74)
26	DAYS SUPPLY	45	47	(2)	(4.26)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,487,588	2,764,610	(277,022)	(10.02)	31,064,284	27,540,901	3,523,383	12.79
29	UNIT COST ($/MMBTU)	3.93	3.68	0.25	6.79	3.69	4.28	(0.59)	(13.79)
30	AMOUNT ($)	9,764,132	10,187,450	(423,318)	(4.16)	114,523,192	117,834,358	(3,311,166)	(2.81)
31	*BURNED :*								
32	UNITS (MMBTU)	2,378,246	2,764,610	(386,364)	(13.98)	31,312,556	27,540,901	3,771,655	13.69
33	UNIT COST ($/MMBTU)	4.00	3.68	0.32	8.70	3.68	4.28	(0.60)	(14.02)
34	AMOUNT ($)	9,512,048	10,187,450	(675,402)	(6.63)	115,261,613	117,834,358	(2,572,745)	(2.18)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	781,306	0	781,306	100.00	781,306	0	781,306	100.00
37	UNIT COST ($/MMBTU)	3.99	0.00	3.99	100.00	3.99	0.00	3.99	100.00
38	AMOUNT ($)	3,119,503	0	3,119,503	100.00	3,119,503	0	3,119,503	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	1,418	767	651	84.88
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	135.30	118.27	17.00	14.37
42	AMOUNT ($)	0	0	0	0.00	191,849	90,715	101,134	111.49
43	*BURNED :*								
44	UNITS (BBL)	165	0	165	100.00	2,290	231	2,059	891.34
45	UNIT COST ($/BBL)	106.90	0.00	106.90	100.00	104.34	105.13	(0.79)	(0.75)
46	AMOUNT ($)	17,638	0	17,638	100.00	238,930	24,285	214,645	883.86
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	5,955	7,058	(1,103)	(15.63)	5,955	7,058	(1,103)	(15.63)
49	UNIT COST ($/BBL)	106.69	104.99	1.70	1.62	106.69	104.99	1.70	1.62
50	AMOUNT ($)	635,314	741,007	(105,693)	(14.26)	635,314	741,007	(105,693)	(14.26)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

	(1)	(2)	CURRENT MONTH (3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		242,000,000	0	242,000,000	2.42	2.74	5,846,000	6,637,000
2	Various	Economy Sales	8,911,000	0	8,911,000	2.51	2.86	224,000	255,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	42,000	42,000
4	TOTAL ESTIMATED SALES		250,911,000	0	250,911,000	2.44	2.76	6,112,000	6,934,000
	ACTUAL								
5	Southern Company Interchange		406,925,172	0	406,925,172	2.73	2.93	11,108,547	11,922,521
6	A.E.C.	External	61,095	0	61,095	2.81	3.65	1,715	2,228
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	AMERENEM	External	0	0	0	0.00	0.00	0	0
10	ARCLIGHT	External	0	0	0	0.00	0.00	0	0
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	0	0	0	0.00	0.00	0	0
13	CARGILE	External	125,634	0	125,634	2.59	3.62	3,252	4,547
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	449,896	0	449,896	2.77	3.30	12,446	14,867
16	CPL	External	0	0	0	0.00	0.00	0	0
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	27,948	0	27,948	2.78	2.47	776	690
19	EAGLE EN	External	54,987	0	54,987	2.96	3.72	1,627	2,046
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	0	0	0	0.00	0.00	0	0
22	ENTERGY	External	0	0	0	0.00	0.00	0	0
23	FPC	External	0	0	0	0.00	0.00	0	0
24	FPL	External	28,467	0	28,467	2.93	3.90	834	1,110
25	JARON	External	0	0	0	0.00	0.00	0	0
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	53,948	0	53,948	2.59	3.44	1,399	1,854
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	0	0	0	0.00	0.00	0	0
31	MORGAN	External	26,000	0	26,000	2.54	3.17	660	824
32	NCEMC	External	0	0	0	0.00	0.00	0	0
33	NCMPA1	External	1,950	0	1,950	5.04	3.60	98	70
34	NRG	External	0	0	0	0.00	0.00	0	0
35	OPC	External	0	0	0	0.00	0.00	1	0
36	ORLANDO	External	1,625	0	1,625	2.40	3.30	39	54
37	PJM	External	446,176	0	446,176	3.00	3.18	13,364	14,199
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	77,988	0	77,988	2.32	3.40	1,806	2,652
40	SEC	External	6,500	0	6,500	2.77	3.55	180	231
41	SEPA	External	1,923,577	0	1,923,577	2.54	3.63	48,924	69,774
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	78,000	0	78,000	2.65	3.05	2,068	2,379
44	TEA	External	899,250	0	899,250	2.75	3.53	24,704	31,781
45	TECO	External	0	0	0	0.00	0.00	0	0
46	TENASKA	External	0	0	0	0.00	0.00	0	0
47	TRANSALT	External	0	0	0	0.00	0.00	0	0
48	TVA	External	3,250	0	3,250	2.62	4.20	85	136
49	UPP	External	0	0	0	0.00	0.00	0	0
50	WRI	External	0	0	0	0.00	0.00	1	0
51	Less: Flow-Thru Energy		(3,912,142)	0	(3,912,142)	2.64	2.64	(103,270)	(103,270)
52	SEPA		1,262,272	1,262,272	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	(801)	(801)
54	Other transactions including adj.		111,962,092	126,748,117	(14,786,025)	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		520,503,685	128,010,389	392,493,296	2.14	2.30	11,118,463	11,968,693
56	Difference in Amount		269,592,685	128,010,389	141,582,296	(0.30)	(0.46)	5,006,463	5,034,693
57	Difference in Percent		107.45	0.00	56.43	(12.30)	(16.67)	81.91	72.61

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			PERIOD TO DATE			(a)	(b)		
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,364,358,000	0	1,364,358,000	3.02	3.39	41,187,000	46,267,000
2	Various	Economy Sales	114,846,000	0	114,846,000	3.40	3.80	3,901,000	4,367,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	661,000	283,000
4	TOTAL ESTIMATED SALES		1,479,204,000	0	1,479,204,000	3.09	3.44	45,749,000	50,917,000
	ACTUAL								
5	Southern Company Interchange		4,385,196,895	0	4,385,196,895	2.58	2.81	113,352,996	123,429,712
6	A.E.C.	External	4,336,287	0	4,336,287	2.79	3.52	121,038	152,718
7	AECI	External	142,854	0	142,854	2.50	3.84	3,569	5,485
8	AEP	External	6,304	0	6,304	3.40	5.50	214	347
9	AMERENEM	External	23,592	0	23,592	0.00	4.10	0	967
10	ARCLIGHT	External	22,685	0	22,685	6.98	4.92	1,584	1,117
11	BPENERGY	External	0	0	0	0.00	0.00	0	0
12	CALPINE	External	777,360	0	777,360	2.77	3.47	21,499	27,001
13	CARGILE	External	5,864,909	0	5,864,909	2.73	3.18	160,148	186,600
14	CITIG	External	0	0	0	0.00	0.00	0	0
15	CONSTELL	External	2,486,560	0	2,486,560	2.62	3.08	65,024	76,470
16	CPL	External	122,636	0	122,636	1.32	1.80	1,619	2,208
17	DTE	External	0	0	0	0.00	0.00	0	0
18	DUKE PWR	External	4,842,850	0	4,842,850	2.26	3.37	109,616	163,008
19	EAGLE EN	External	1,802,476	0	1,802,476	2.56	3.51	46,086	63,186
20	EASTKY	External	0	0	0	0.00	0.00	0	0
21	ENDURE	External	123,353	0	123,353	2.46	4.01	3,030	4,952
22	ENTERGY	External	14,920,480	0	14,920,480	3.36	6.79	501,245	1,012,864
23	FPC	External	523,955	0	523,955	4.11	5.18	21,523	27,164
24	FPL	External	4,202,649	0	4,202,649	2.83	4.04	119,009	169,956
25	JARON	External	228,847	0	228,847	3.31	5.04	7,586	11,525
26	JEA	External	0	0	0	0.00	0.00	0	0
27	JPMVEC	External	1,337,831	0	1,337,831	2.67	3.43	35,723	45,906
28	KEMG	External	0	0	0	0.00	0.00	0	0
29	MERRILL	External	0	0	0	0.00	0.00	0	0
30	MISO	External	325	0	325	2.71	2.00	9	7
31	MORGAN	External	2,138,224	0	2,138,224	2.88	3.23	61,675	69,082
32	NCEMC	External	13,974	0	13,974	1.95	2.83	272	395
33	NCMPA1	External	1,023,800	0	1,023,800	2.95	3.35	30,192	34,309
34	NRG	External	75,066	0	75,066	3.68	5.03	2,763	3,776
35	OPC	External	2,150,453	0	2,150,453	2.61	3.33	56,063	71,675
36	ORLANDO	External	21,772	0	21,772	2.63	3.73	573	813
37	PJM	External	11,244,898	0	11,244,898	2.27	3.34	255,687	375,054
38	REMC	External	0	0	0	0.00	0.00	0	0
39	SCE&G	External	5,515,476	0	5,515,476	3.18	4.33	175,654	238,594
40	SEC	External	2,123,223	0	2,123,223	2.46	3.17	52,168	67,280
41	SEPA	External	10,390,376	0	10,390,376	2.43	3.12	252,132	324,123
42	SHELL	External	0	0	0	0.00	0.00	0	0
43	TAL	External	2,488,915	0	2,488,915	3.29	4.44	81,904	110,422
44	TEA	External	11,818,754	0	11,818,754	2.41	3.28	284,511	387,407
45	TECO	External	411,994	0	411,994	2.53	3.84	10,407	15,820
46	TENASKA	External	30,742	0	30,742	3.11	4.37	957	1,342
47	TRANSALT	External	6,500	0	6,500	2.25	3.20	147	208
48	TVA	External	1,049,420	0	1,049,420	2.61	3.81	27,357	40,032
49	UPP	External	19,498	0	19,498	3.30	2.50	643	487
50	WRI	External	288,337	0	288,337	2.70	3.39	7,799	9,778
51	Less: Flow-Thru Energy		(91,886,623)	0	(91,886,623)	2.69	2.69	(2,476,218)	(2,476,218)
52	SEPA		13,533,606	13,533,606	0	0.00	0.00	0	0
53	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	519,586	519,586
54	Other transactions including adj.		2,536,437,114	1,989,242,875	547,194,239	0.00	0.00	0	0
55	TOTAL ACTUAL SALES		6,935,858,367	2,002,776,481	4,933,081,886	1.64	1.80	113,915,789	124,655,572
56	Difference in Amount		5,456,654,367	2,002,776,481	3,453,877,886	(1.45)	(1.64)	68,166,789	73,738,572
57	Difference in Percent		368.89	0.00	233.50	(46.93)	(47.67)	149.00	144.82

Note: (1) Economy Sales Gains in column 8 are included in the total cost for each counterparty and are not included as depicted on line 53

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) ¢ / KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (6)x(7)(a)
ESTIMATED:								
NONE								
ACTUAL:								
NONE								

SCHEDULE A-8

ENERGY PAYMENT TO QUALIFIED FACILITIES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

CURRENT MONTH

(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	1,435
5 Ascend Performance Materials	COG 1	24,042,000	0	0	0	2.91	2.91	700,415
6 International Paper	COG 1	14,000	0	0	0	34.97	34.97	4,896
7 TOTAL		24,056,000	0	0	0	2.94	2.94	706,746

PERIOD-TO-DATE

(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	4,226,000	0	0	0	7.50	7.50	317,072
3 Pensacola Christian College	COG 1	0	0	0	0	0.00	0.00	0
4 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	1,487
5 Ascend Performance Materials	COG 1	213,626,000	0	0	0	2.80	2.80	5,972,614
6 International Paper	COG 1	995,000	0	0	0	3.31	3.31	32,954
7 TOTAL		218,847,000	0	0	0	2.89	2.89	6,324,127

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2012

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	23,646,000	2.99	707,000	1,092,513,000	3.68	40,257,000
2	Economy Energy	6,744,000	2.73	184,000	60,494,000	3.66	2,214,000
3	Other Purchases	499,429,000	2.85	14,225,000	2,676,502,000	2.47	66,237,000
4	TOTAL ESTIMATED PURCHASES	529,819,000	2.85	15,116,000	3,829,509,000	2.84	108,708,000
	ACTUAL						
5	Southern Company Interchange	77,594,376	3.11	2,414,014	944,249,674	2.81	26,518,764
6	Non-Associated Companies	43,483,666	0.57	249,283	380,887,418	(0.55)	(2,077,761)
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	569,541,000	2.99	17,043,940	6,286,432,000	2.56	160,843,032
9	Other Wheeled Energy	7,464,000	0.00	N/A	849,947,000	0.00	N/A
10	Other Transactions	71,793,143	0.02	13,722	1,540,807,604	0.02	307,097
11	Less: Flow-Thru Energy	(3,912,142)	2.86	(111,768)	(91,886,623)	2.95	(2,709,280)
12	TOTAL ACTUAL PURCHASES	765,964,043	2.56	19,609,191	9,910,437,073	1.85	182,881,852
13	Difference in Amount	236,145,043	(0.29)	4,493,191	6,080,928,073	(0.99)	74,173,852
14	Difference in Percent	44.57	(10.18)	29.72	158.79	(34.86)	68.23

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	564.6	791,448	337.7	152,312	309.1	267,339	63.7	10,862	0	5,692	0	0	1,227,653
SUBTOTAL					$ 791,448		$ 152,312		$ 267,339		$ 10,862		$ 5,692		$ -	$ 1,227,653
B. CONFIDENTIAL CAPACITY CONTRACTS																
1 Power Purchase Agreements	Other	Varies	Varies	Varies	1,598,449	Varies	1,584,591	Varies	1,487,018	Varies	1,477,131	Varies	2,070,759	Varies	7,643,985	15,861,933
2 Other Confidential Agreements	Other	Varies	Varies	Varies	(10,503)	Varies	(3,708)	Varies	(3,950)	Varies	(3,719)	Varies	(4,498)	Varies	(3,562)	(29,940)
SUBTOTAL					$ 1,587,946		$ 1,580,883		$ 1,483,068		$ 1,473,412		$ 2,066,261		$ 7,640,423	$ 15,831,993
TOTAL					**$ 2,379,394**		**$ 1,733,195**		**$ 1,750,407**		**$ 1,484,274**		**$ 2,071,953**		**$ 7,640,423**	**$ 17,059,646**

2012 CAPACITY CONTRACTS
GULF POWER COMPANY

		(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
					JUL		AUG		SEP		OCT		NOV		DEC		YTD
A.	CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1	Southern Intercompany Interchange	SES Opco	2/18/2000	5 Yr Notice	0	0	0	0	57	371,149	(116.5)	(84,799)	165.6	63,041	(22.5)	(140,794)	1,436,250
	SUBTOTAL					$ -		$ -		$ 371,149		$ (84,799)		$ 63,041		$ (140,794)	$ 1,436,250
B.	CONFIDENTIAL CAPACITY CONTRACTS																
1	Power Purchase Agreements	Other	Varies	Varies	Varies	8,266,469	Varies	7,144,861	Varies	6,755,384	Varies	1,978,232	Varies	1,978,232	Varies	1,872,322	43,857,433
2	Other Confidential Agreements	Other	Varies	Varies	Varies	(5,502)	Varies	(8,163)	Varies	(3,883)	Varies	(3,087)	Varies	(4,884)	Varies	(3,249)	(58,708)
	SUBTOTAL					$ 8,260,967		$ 7,136,698		$ 6,751,501		$ 1,975,145		$ 1,973,348		$ 1,869,073	$ 43,798,725
	TOTAL					**$ 8,260,967**		**$ 7,136,698**		**$ 7,122,650**		**$ 1,890,346**		**$ 2,036,389**		**$ 1,728,279**	**$ 45,234,975**

Schedule E-1A

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
TO BE INCLUDED IN THE PERIOD JANUARY 2014 - DECEMBER 2014

1.	Estimated over/(under)-recovery for the period January 2013 - December 2013 (Sch. E-1B, Page 2, line C9)	$	(6,665,066)
2.	Final over/(under)-recovery for the period January 2012 - December 2012 (Exhibit RWD-1, Schedule 1, line 3)		(9,333,695)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2014 - December 2014		(15,998,761)
4.	Jurisdictional kWh sales for the period January 2014 - December 2014		11,154,278,000
5.	True-Up Factor (Line 3/Line 4) x 100(¢/kWH)		0.1434

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 42
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION R.W. Dodd - RWD-2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	23,612,216.88	21,601,356.61	24,302,567.18	27,852,455.30	26,252,165.97	40,413,751.45	$164,034,513.39
	1a	Fuel Cost of Hedging Settlement	2,013,400.00	2,166,655.00	793,231.00	403,524.00	493,084.00	916,010.00	$6,785,904.00
	2	Fuel Cost of Power Sold	(8,475,749.46)	(10,067,800.03)	(8,847,411.42)	(4,579,035.77)	(5,374,663.85)	(8,298,519.65)	($45,643,180.18)
	3	Fuel Cost of Purchased Power	16,459,115.59	16,261,329.94	18,166,866.50	11,459,751.39	16,278,229.43	17,619,494.27	$96,244,787.12
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities	628,657.17	744,198.26	940,575.93	996,575.97	895,426.55	851,224.12	$5,056,658.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	183,550.37	199,409.00	221,861.59	217,561.76	215,342.86	223,621.47	$1,261,347.05
	6	Adjustments to Fuel Cost *	6,952.10	79,735.13	13,168.04	16,269.98	(9,788.63)	15,967.75	$122,304.37
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	34,428,142.65	30,984,883.91	35,590,858.82	36,367,102.63	$38,749,796.33	$51,741,549.41	$227,862,333.75
B	1	Jurisdictional KWH Sales	778,963,209	705,542,522	793,160,952	730,244,171	883,344,861	1,078,668,799	4,969,924,514
	2	Non-Jurisdictional KWH Sales	24,917,444	22,515,414	24,361,046	21,950,706	25,381,308	29,535,698	148,661,616
	3	TOTAL SALES (Lines B1 + B2)	803,880,653	728,057,936	817,521,998	752,194,877	908,726,169	1,108,204,497	5,118,586,130
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.9004%	96.9075%	97.0201%	97.0818%	97.2069%	97.3348%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	29,539,374.46	26,749,927.96	30,090,473.26	27,703,808.92	33,545,795.79	40,974,608.87	$188,603,989.26
	2	True-Up Provision	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	$13,212,708.00
	2a	Incentive Provision	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	($519,954.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$31,654,833.46	$28,865,386.96	$32,205,932.26	$29,819,267.92	$35,661,254.79	$43,090,067.87	$201,296,743.26
	4	Fuel & Net Power Transactions (Line A7)	34,428,142.65	30,984,883.91	35,590,858.82	36,367,102.63	38,749,796.33	51,741,549.41	$227,862,333.75
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	33,411,049.45	30,071,716.39	34,582,082.25	35,358,796.60	37,723,976.98	50,438,077.44	$221,585,699.11
	6	Over/(Under) Recovery (Line C3-C5)	(1,756,215.99)	(1,206,329.43)	(2,376,149.99)	(5,539,528.68)	(2,062,722.19)	(7,348,009.57)	($20,288,955.85)
	7	Interest Provision	876.53	902.97	557.82	85.64	(297.67)	(628.17)	$1,497.12
	8	Adjustments (2)	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2013 - JUNE 2013**							($20,287,458.73)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note 1: Revenues for July through December based on the current approved 2013 Fuel Factor excluding revenue taxes of: 3.7999
Note 2: Satisfaction of Peabody judgement

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

			JULY PROJECTION	AUGUST PROJECTION	SEPTEMBER PROJECTION	OCTOBER PROJECTION	NOVEMBER PROJECTION	DECEMBER PROJECTION	TOTAL PERIOD
			(a)	(a)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	43,191,597.00	39,519,080.00	38,325,558.00	29,526,224.00	24,020,574.00	28,882,719.00	$367,500,265.39
	1a	Fuel Cost of Hedging Settlement	0.00	0.00	0.00	0.00	0.00	0.00	$6,785,904.00
	2	Fuel Cost of Power Sold	(14,656,000.00)	(13,509,000.00)	(7,957,000.00)	(6,605,000.00)	(7,662,000.00)	(9,516,000.00)	($105,548,180.18)
	3	Fuel Cost of Purchased Power	21,784,000.00	22,937,000.00	16,031,000.00	15,756,000.00	16,659,000.00	18,753,000.00	$208,164,787.12
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities	0.00	0.00	0.00	0.00	0.00	0.00	$5,056,658.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	286,819.00	286,819.00	277,584.00	191,391.00	185,235.00	191,391.00	$2,680,586.05
	6	Adjustments to Fuel Cost *	0.00	0.00	0.00	0.00	0.00	0.00	$122,304.37
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$50,606,416.00	$49,233,899.00	$46,677,142.00	$38,868,615.00	$33,202,809.00	$38,311,110.00	$484,762,324.75
B	1	Jurisdictional KWH Sales	1,198,377,000	1,181,726,000	1,034,929,000	865,410,000	762,800,000	852,320,000	10,865,486,514
	2	Non-Jurisdictional KWH Sales	34,430,000	34,820,000	30,495,000	26,329,000	24,784,000	28,961,000	328,480,616
	3	TOTAL SALES (Lines B1 + B2)	1,232,807,000	1,216,546,000	1,065,424,000	891,739,000	787,584,000	881,281,000	11,193,967,130
	4	Jurisdictional % Of Total Sales (Line B1/B3)	97.2072%	97.1378%	97.1378%	97.0475%	96.8532%	96.7138%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	45,536,697.38	44,903,982.01	39,325,895.51	32,884,403.89	28,985,363.34	32,387,001.68	$412,627,333.06
	2	True-Up Provision	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,120.00	$26,425,418.00
	2a	Incentive Provision	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,662.00)	($1,039,911.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$47,652,156.38	$47,019,441.01	$41,441,354.51	$34,999,862.89	$31,100,822.34	$34,502,459.68	$438,012,840.06
	4	Fuel & Net Power Transactions (Line A7)	50,606,416.00	49,233,899.00	46,677,142.00	38,868,615.00	33,202,809.00	38,311,110.00	$484,762,324.75
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	49,266,869.63	47,896,463.43	45,409,160.56	37,777,600.67	32,206,219.98	37,107,708.50	$471,249,721.88
	6	Over/(Under) Recovery (Line C3-C5)	(1,614,713.25)	(877,022.42)	(3,967,806.05)	(2,777,737.78)	(1,105,397.64)	(2,605,248.82)	($33,236,881.81)
	7	Interest Provision	412.71	240.33	9.12	(269.63)	(476.82)	(679.72)	$733.11
	8	Adjustments (2)	26,571,082.26	0.00	0.00	0.00	0.00	0.00	$26,571,082.26
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2013 - DECEMBER 2013**							($6,665,066.44)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note 1: Revenues for July through December based on the current approved 2013 Fuel Factor excluding revenue taxes of: 3.7999
Note 2: Satisfaction of Peabody judgement

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

		DOLLARS				kWh				¢/kWh			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation	367,500,265	358,100,519	9,399,746	2.62	8,600,677,000	8,710,307,000	(109,630,000)	(1.26)	4.2729	4.1112	0.1617	3.93
1a	Fuel Cost of Hedging Settlement	6,785,904	0	6,785,904	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4	Other Generation	2,680,586	1,814,318	866,268	47.75	80,118,000	50,524,000	29,594,000	58.57	3.3458	3.5910	(0.2452)	(6.83)
5	Adjustments to Fuel Cost ***	122,304	0	122,304	100.00	0	0				0.0000		
6	TOTAL COST OF GENERATED POWER	377,089,060	359,914,837	17,174,223	4.77	8,680,795,000	8,760,831,000	(80,036,000)	(0.91)	4.3439	4.1082	0.2357	5.74
7	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
8	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
9	Energy Cost of Other Economy Purchases (Nonbroker)	208,164,787	185,816,000	22,348,787	12.03	7,070,734,558	6,164,950,000	905,784,558	14.69	2.9440	3.0141	(0.0701)	(2.33)
10	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
12	Energy Payments to Qualifying Facilities	5,056,658	0	5,056,658	100.00	133,774,000	0	133,774,000	100.00	3.7800	0.0000	3.7800	100.00
13	TOTAL COST OF PURCHASED POWER	213,221,445	185,816,000	27,405,445	14.75	7,204,508,558	6,164,950,000	1,039,558,558	16.86	2.9596	3.0141	(0.0545)	(1.81)
14	Total Available kWh (Line 6 + Line 13)	590,310,505	545,730,837	44,579,668	8.17	15,885,303,558	14,925,781,000	959,522,558	6.43	3.7161	3.6563	0.0598	1.64
15	Fuel Cost of Economy Sales	(2,472,023)	(2,428,000)	(44,023)	1.81	(75,136,816)	(77,479,000)	2,342,184	(3.02)	3.2900	3.1338	0.1562	4.98
16	Gain on Economy Sales	(405,832)	(645,241)	239,409	(37.10)	0	0						
17	Fuel Cost of Other Power Sales	(102,670,325)	(73,242,000)	(29,428,325)	40.18	(3,916,300,111)	(2,449,607,000)	(1,466,693,111)	59.87	2.6216	2.9899	(0.3683)	(12.32)
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 15+16+17)	(105,548,180)	(76,315,241)	(29,232,939)	38.31	(3,991,436,927)	(2,527,086,000)	(1,464,350,927)	57.95	2.6444	3.0199	(0.3755)	(12.43)
20	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
21	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 14+18+20)	484,762,325	469,415,596	15,346,729	3.27	11,893,866,631	12,398,695,000	(504,828,369)	(4.07)	4.0757	3.7860	0.2897	7.65
22	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
23	Company Use *	844,359	820,767	23,592	2.87	20,716,904	21,679,000	(962,096)	(4.44)	4.0757	3.7860	0.2897	7.65
24	T & D Losses *	27,681,445	26,311,754	1,369,691	5.21	679,182,597	694,975,000	(15,792,403)	(2.27)	4.0757	3.7860	0.2897	7.65
25	TERRITORIAL (SYSTEM) SALES	484,762,325	469,415,596	15,346,729	3.27	11,193,967,130	11,682,041,000	(488,073,870)	(4.18)	4.3306	4.0183	0.3123	7.77
26	Wholesale Sales	14,225,075	14,983,638	(758,563)	(5.06)	328,480,616	372,885,000	(44,404,384)	(11.91)	4.3306	4.0183	0.3123	7.77
27	Jurisdictional Sales	470,537,250	454,431,958	16,105,292	3.54	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	4.3306	4.0183	0.3123	7.77
28	Jurisdictional Loss Multiplier	1.0015	1.0015										
29	Jurisdictional Sales Adj. for Line Losses (Line 27 x 1.0015)	471,249,722	455,113,606	16,136,116	3.55	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	4.3371	4.0243	0.3128	7.77
30	TRUE-UP **	(26,425,418)	(26,425,418)	0	0.00	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	(0.2432)	(0.2337)	(0.0095)	4.07
31	TOTAL JURISDICTIONAL FUEL COST	444,824,304	428,688,188	16,136,116	3.76	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	4.0939	3.7906	0.3033	8.00
32	Revenue Tax Factor									1.00072	1.00072		
33	Fuel Factor Adjusted for Revenue Taxes									4.0968	3.7933	0.3035	8.00
34	GPIF Reward / (Penalty) **	1,040,660	1,040,660	0	0.00	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	0.0096	0.0092	0.0004	(4.35)
35	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1064	3.8025	0.3039	7.99
36	**FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									4.106	3.803	0.3030	7.97

* Included for informational purposes only.

** ¢/kWh calculation based on jurisdictional kWh sales.

*** (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note: Amounts included in the Estimated/Actual column represent 6 months actual and 6 months estimate.

SCHEDULE E-2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

LINE	LINE DESCRIPTION	(a) JANUARY ACTUAL	(b) FEBRUARY ACTUAL	(c) MARCH ACTUAL	(d) APRIL ACTUAL	(e) MAY ACTUAL	(f) JUNE ACTUAL	(g) JULY ESTIMATED	(h) AUGUST ESTIMATED	(i) SEPTEMBER ESTIMATED	(j) OCTOBER ESTIMATED	(k) NOVEMBER ESTIMATED	(l) DECEMBER ESTIMATED	(m) TOTAL
	$													
1	Fuel Cost of System Generation	23,612,216.88	21,601,356.61	24,302,567.18	27,852,455.30	26,252,165.97	40,413,751.45	43,191,597	39,519,080	38,325,558	29,526,224	24,020,574	28,882,719	367,500,265.39
1a	Other Generation	183,550.37	199,409.00	221,861.59	217,561.76	215,342.86	223,621.47	286,819	286,819	277,584	191,391	185,235	191,391	2,680,586.05
2	Fuel Cost of Power Sold	(8,475,749.46)	(10,067,800.03)	(8,847,411.42)	(4,579,035.77)	(5,374,663.85)	(8,298,519.65)	(14,656,000)	(13,509,000)	(7,957,000)	(6,605,000)	(7,662,000)	(9,516,000)	(105,548,180.18)
3	Fuel Cost of Purchased Power	16,459,115.59	16,261,329.94	18,166,866.50	11,459,751.39	16,278,229.43	17,619,494.27	21,784,000	22,937,000	16,031,000	15,756,000	16,659,000	18,753,000	208,164,787.12
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0.00
3b	Qualifying Facilities	628,657.17	744,198.26	940,575.93	996,575.97	895,426.55	851,224.12	0	0	0	0	0	0	5,056,658.00
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0.00
5	Hedging Settlement	2,013,400.00	2,166,655.00	793,231.00	403,524.00	493,084.00	916,010.00	0	0	0	0	0	0	6,785,904.00
6	Adjustment to Fuel Cost	6,952.10	79,735.13	13,168.04	16,269.98	(9,788.63)	15,967.75	0	0	0	0	0	0	122,304.37
7	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 6)	$ 34,428,142.65	$ 30,984,883.91	$ 35,590,858.82	$ 36,367,102.63	$ 38,749,796.33	$ 51,741,549.41	$ 50,606,416.00	$ 49,233,899.00	$ 46,677,142.00	$ 38,868,615.00	$ 33,202,809.00	$ 38,311,110.00	$ 484,762,324.75
8	System kWh Sold	803,880,653	728,057,936	817,521,998	752,194,877	908,726,169	1,108,204,497	1,232,807,000	1,216,546,000	1,065,424,000	891,739,000	787,584,000	881,281,000	11,193,967,130
8a	Jurisdictional % of Total Sales	0.9690	0.9691	0.9702	0.9708	0.9721	0.9733	0.9721	0.9714	0.9714	0.9705	0.9685	0.9671	96.8624
9	Cost per kWh Sold (¢/kWh)	4.2827	4.2558	4.3535	4.8348	4.2642	4.6690	4.1050	4.0470	4.3811	4.3587	4.2158	4.3472	4.3306
9a	Jurisdictional Loss Multiplier	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015
9b	Jurisdictional Cost (¢/kWh)	4.2891	4.2622	4.3600	4.8421	4.2706	4.6760	4.1112	4.0531	4.3877	4.3652	4.2221	4.3537	4.3371
10	GPIF (¢/kWh) *	0.0111	0.0123	0.0109	0.0119	0.0098	0.0080	0.0072	0.0073	0.0084	0.0100	0.0114	0.0102	0.0096
11	True-Up (¢/kWh) *	(0.2827)	(0.3121)	(0.2776)	(0.3016)	(0.2493)	(0.2042)	(0.1838)	(0.1863)	(0.2128)	(0.2545)	(0.2887)	(0.2584)	(0.2432)
12	TOTAL	4.0175	3.9624	4.0933	4.5524	4.0311	4.4798	3.9346	3.8741	4.1833	4.1207	3.9448	4.1055	4.1035
13	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
14	Recovery Factor Adjusted for Taxes	4.0204	3.9653	4.0962	4.5557	4.0340	4.4830	3.9374	3.8769	4.1863	4.1237	3.9476	4.1085	4.1065
15	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	4.020	3.965	4.096	4.556	4.034	4.483	3.937	3.877	4.186	4.124	3.948	4.109	4.106

* ¢/kWh calculations based on jurisdictional kWh sales

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	42,250	209,940	317,402	200,571	109,031	155,555	138,937	138,719	138,589	138,490	134,445	103,416	1,827,345
2	COAL	14,091,358	11,093,978	16,738,493	19,432,765	15,021,429	29,763,111	31,004,467	27,286,890	26,560,450	19,718,648	12,744,995	16,428,286	239,884,870
3	GAS - Generation	9,558,242	10,419,732	7,378,147	8,287,922	11,221,480	10,501,521	12,261,473	12,315,454	11,849,835	9,804,365	11,272,101	12,486,296	127,356,568
4	GAS (B.L.)	17,434	0	13,904	74,805	31,203	143,481	0	0	0	0	0	0	280,827
5	Landfill Gas	63,239	58,444	59,508	52,342	63,553	59,830	56,112	56,112	54,268	56,112	54,268	56,112	689,900
6	OIL - C.T.	23,244	18,672	16,974	21,611	20,813	13,875	17,427	8,724	0	0	0	0	141,340
7	TOTAL ($)	23,795,767	21,800,766	24,524,428	28,070,017	26,467,509	40,637,373	43,478,416	39,805,899	38,603,142	29,717,615	24,205,809	29,074,110	370,180,851
	SYSTEM NET GEN. (MWH)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	284,995	212,749	345,589	382,401	335,012	598,151	654428	571743	544785	403247	264797	340147	4,938,044
10	GAS	337,120	358,648	236,030	207,165	290,294	271,781	355537	359375	344967	270154	326216	360379	3,717,666
11	Landfill Gas	2,170	2,014	2,052	1,796	2,152	1,984	2100	2100	2031	2100	2031	2100	24,630
12	OIL - C.T.	74	67	54	67	61	36	64	32	0	0	0	0	455
13	TOTAL (MWH)	624,359	573,478	583,725	591,429	627,519	871,952	1,012,129	933,250	891,783	675,501	593,044	702,626	8,680,795
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	339	1,542	2,356	1,555	845	1,241	1,094	1,094	1,094	1,094	1,063	817	14,134
15	COAL (TON)	135,335	105,358	163,849	185,277	145,535	283,844	299,919	260,595	249,570	186,124	122,384	156,826	2,294,616
16	GAS-all (MCF) (1)	2,349,243	2,640,194	1,616,202	1,522,511	2,035,339	1,938,257	2,441,784	2,470,947	2,368,540	1,825,897	2,204,437	2,437,745	25,851,096
17	OIL - C.T. (BBL)	215	173	157	197	188	126	154	77	0	0	0	0	1,287
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + OIL B.L.	3,173,845	2,415,027	3,818,324	4,267,898	3,694,825	6,511,202	7,068,370	6,154,866	5,841,596	4,424,493	2,962,447	3,771,542	54,104,435
19	GAS-Generation (1)	2,384,244	2,680,234	1,637,821	1,538,071	2,007,507	1,950,805	2,515,037	2,545,076	2,439,596	1,880,674	2,270,570	2,510,877	26,360,512
20	OIL - C.T.	1,261	1,013	921	1,138	1,086	724	900	450	0	0	0	0	7,493
21	TOTAL (MMBTU)	5,559,350	5,096,274	5,457,066	5,807,107	5,703,418	8,462,731	9,584,307	8,700,392	8,281,192	6,305,167	5,233,017	6,282,419	80,472,440

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	GENERATION MIX (% MWH)													
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	45.65	37.10	59.20	64.66	53.39	68.60	64.65	61.26	61.09	59.70	44.65	48.41	56.88
24	GAS-Generation	53.99	62.54	40.44	35.03	46.26	31.17	35.13	38.51	38.68	39.99	55.01	51.29	42.83
25	Landfill Gas	0.35	0.35	0.35	0.30	0.34	0.23	0.21	0.23	0.23	0.31	0.34	0.30	0.28
26	OIL - C.T.	0.01	0.01	0.01	0.01	0.01	0.00	0.01		0.00	0.00	0.00	0.00	0.01
27	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
28	LIGHTER OIL ($/BBL)	124.63	136.15	134.72	128.98	129.03	125.35	127.00	126.80	126.68	126.59	126.48	126.58	129.29
29	COAL ($/TON)	104.12	105.30	102.16	104.88	103.22	104.86	103.38	104.71	106.42	105.94	104.14	104.75	104.54
30	GAS + B.L. ($/MCF) (1)	4.00	3.87	4.44	5.35	5.42	5.38	4.90	4.87	4.89	5.26	5.03	5.04	4.83
31	OIL - C.T.	108.11	107.93	108.12	109.70	110.71	110.12	113.34	113.47	0.00	0.00	0.00	0.00	109.85
	FUEL COST $ / MMBTU													
32	COAL + GAS B.L. + OIL B.L.	4.46	4.68	4.47	4.62	4.10	4.62	4.41	4.46	4.57	4.49	4.35	4.38	4.47
33	GAS-Generation (1)	3.93	3.81	4.37	5.25	5.48	5.27	4.76	4.73	4.74	5.11	4.88	4.90	4.73
34	OIL - C.T.	18.43	18.43	18.43	18.99	19.16	19.16	19.36	19.39	0.00	0.00	0.00	0.00	18.86
35	TOTAL ($/MMBTU)	4.24	4.23	4.44	4.79	4.59	4.77	4.51	4.54	4.63	4.68	4.59	4.60	4.57
	BTU BURNED BTU / KWH													
36	COAL + GAS B.L. + OIL B.L.	11,136	11,352	11,049	11,161	11,029	10,886	10,801	10,765	10,723	10,972	11,188	11,088	10,957
37	GAS-Generation (1)	7,190	7,606	7,139	7,664	7,074	7,349	7,249	7,255	7,246	7,112	7,080	7,080	7,247
38	OIL - C.T.	17,041	15,119	17,056	16,985	17,803	20,111	14,063	14,063	0	0	0	0	16,468
39	TOTAL (BTU/KWH)	9,015	9,017	9,490	9,958	9,216	9,799	9,550	9,409	9,373	9,414	8,907	9,015	9,357
	FUEL COST CENTS / KWH													
40	COAL + GAS B.L. + OIL B.L.	4.97	5.31	4.94	5.15	4.53	5.03	4.76	4.80	4.90	4.92	4.86	4.86	4.90
41	GAS-Generation	2.84	2.91	3.13	4.00	3.87	3.86	3.45	3.43	3.44	3.63	3.46	3.46	3.43
42	Landfill Gas	2.91	2.90	2.90	2.91	2.95	3.02	2.67	2.67	2.67	2.67	2.67	2.67	2.80
43	OIL - C.T.	31.41	27.87	31.43	32.26	34.12	38.54	27.23	27.26	0.00	0.00	0.00	0.00	31.06
44	TOTAL (¢/KWH)	3.81	3.80	4.20	4.75	4.22	4.66	4.30	4.27	4.33	4.40	4.08	4.14	4.26

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./ct/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	3,661	6.7	100.0	61.5	10,859	Coal	1,752	11,346	39,753	177,271	4.84	101.18
2				66					Gas-G	704	1,013	713	4,975	7.54	7.07
3									Gas-S	0	1,013	0	0.00		0.00
4									Oil-S	53	138,572	306	6,326		119.36
5	Crist 5		75	32,566	62.6	100.0	66.4	11,070	Coal	15,418	11,691	360,504	1,560,156	4.79	101.19
6				2,357					Gas-G	25,842	1,013	26,178	182,763	7.75	7.07
7									Gas-S	1,464	1,013	1,483	10,354.33		7.07
8									Oil-S	156	138,572	908	18,766		120.29
9	Crist 6		291	(1,641)	(0.8)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,013	0	0	0.00	0.00
11									Gas-S	0	1,013	0	0.00		0.00
12									Oil-S	0	138,572	0	0		0.00
13	Crist 7		465	198,503	57.7	99.3	58.1	10,916	Coal	92,495	11,713	2,166,796	9,359,632	4.72	101.19
14				997					Gas-G	1,052	1,013	1,066	7,441	0.75	7.07
15									Gas-S	1,001	1,013	1,014	7,080.07		7.07
16									Oil-S	20	138,572	114	2,353		117.65
17	Scholz 1		46	(237)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(184)	(0.5)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	54,573	45.3	100.0	45.3	11,037	Coal	25,670	11,732	602,316	2,780,090	5.09	108.30
22									Oil-S	111	139,719	651	14,806		133.39
23	Smith 2		195	(378)	(0.3)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	139,719	0	0		0.00
25	Smith 3		584	328,166	75.5	98.1	83.2	7,180	Gas-G	2,319,180	1,016	2,356,287	9,179,512	2.80	3.96
26	Smith A	(2)	40	74	0.2	99.8	33.3	17,041	Oil	215	139,688	1,261	23,244	31.41	108.11
27	Other Generation			5,534									183,550	3.32	0.00
28	Perdido			2,170					Landfill Gas				63,239	2.91	0.00
29	Daniel 1	(1)	255	(1,319)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	140,433	0	0		0.00
31	Daniel 2	(1)	255	(549)	(0.3)	68.6	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	140,433	0	0		0.00
33	Total		2,489	624,359	33.7	96.2	37.7	9,015				5,559,350	23,581,558	3.78	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
-	Coal Additive	218,268	
	Recoverable Fuel	23,795,767	

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(742)	0.0	65.2	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,016	0	0	0.00	0.00
3									Gas-S	0	1,016	0	0		0.00
4									Oil-S	0	138,572	0	0		0.00
5	Crist 5		75	36,338	74.3	100.0	74.3	10,908	Coal	17,121	11,575	396,360	1,729,301	4.76	101.00
6				1,093					Gas-G	11,708	1,016	11,895	42,941	3.93	3.67
7									Gas-S	0	1,016	0	0		0.00
8									Oil-S	128	138,572	746	15,410		120.39
9	Crist 6		299	(1,414)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	0	1,016	0	0		0.00
12									Oil-S	0	138,572	0	0		0.00
13	Crist 7		475	129,802	52.7	100.0	52.7	11,262	Coal	62,827	11,634	1,461,857	6,345,688	4.89	101.00
14				38,357					Gas-G	425,146	1,016	431,949	1,559,325	4.07	3.67
15									Gas-S	0	1,016	0	0		0.00
16									Oil-S	20	138,572	114	2,348		117.40
17	Scholz 1		46	(204)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(167)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	49,807	45.8	100.0	45.8	10,998	Coal	24,309	11,267	547,782	2,650,340	5.32	109.03
22									Oil-S	1,085	139,329	6,346	149,587		137.87
23	Smith 2		195	(266)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	139,329	0	0		0.00
25	Smith 3		584	312,942	79.7	98.1	88.7	7,146	Gas-G	2,203,340	1,015	2,236,390	8,618,057	2.75	3.91
26	Smith A	(2)	40	67	0.2	100.0	75.6	15,119	Oil	173	139,688	1,013	18,672	27.87	107.93
27	Other Generation			6,256									199,409	3.19	0.00
28	Perdido			2,014					Landfill Gas				58,444	2.90	0.00
29	Daniel 1	(1)	255	(64)	0.0	95.5	0.0	0	Coal	1,101	0	0	119,119	0.00	108.19
30									Oil-S	310	140,023	1,822	42,595		137.40
31	Daniel 2	(1)	255	(341)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
32									Oil-S	0	140,023	0	0.00		0.00
33	Total		2,507	573,478	34.0	87.9	37.0	9,017				5,096,274	21,551,236	3.76	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
-	Coal Additive - Crist	270,576	
-	Inventory Adj - Coal, Crist	(28,018)	
-	Inventory Adj - Coal, Smith	11,031	
	Recoverable Fuel	21,800,766	

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./ct/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(793)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,016	0	0	0.00	0.00
3									Gas-S	0	1,016	0	0		0.00
4									Oil-S	0	138,572	0	0		0.00
5	Crist 5		75	36,136	64.9	100.0	64.9	11,160	Coal	17,266	11,678	403,262	1,707,690	4.73	98.90
6				41					Gas-G	4,504	1,016	4,576	23,641	57.66	5.25
7									Gas-S	808	1,016	821	4,240		5.25
8									Oil-S	217	138,572	1,265	26,842		123.70
9	Crist 6		299	(1,579)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	0	1,016	0	0		0.00
12									Oil-S	0	138,572	0	0		0.00
13	Crist 7		475	178,314	52.2	98.6	52.9	10,689	Coal	81,010	11,764	1,905,997	8,012,298	4.49	98.91
14				5,819					Gas-G	61,302	1,016	62,283	321,737	5.53	5.25
15									Gas-S	1,842	1,016	1,871	9,665		5.25
16									Oil-S	45	138,572	260	5,526		122.80
17	Scholz 1		46	8,129	23.8	100.0	57.0	12,798	Coal	4,597	11,315	104,034	399,705	4.92	86.95
18									Oil-S	38	137,647	220	4,971		130.82
19	Scholz 2		46	(196)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	59,769	49.7	100.0	49.7	10,929	Coal	29,394	11,111	653,197	3,171,406	5.31	107.89
22									Oil-S	394	137,846	2,282	52,656		133.64
23	Smith 2		195	28,459	19.6	99.8	45.5	10,938	Coal	14,667	10,612	311,293	1,582,463	5.56	107.89
24									Oil-S	279	137,846	1,617	37,308		133.72
25	Smith 3		558	223,548	53.9	65.2	84.0	7,027	Gas-G	1,547,746	1,015	1,570,962	6,810,907	3.05	4.40
26	Smith A	(2)	36	54	0.2	100.0	72.3	17,056	Oil	157	139,688	921	16,974	31.43	108.11
27	Other Generation			6,622									221,862	3.35	0.00
28	Perdido			2,052					Landfill Gas				59,508	2.90	0.00
29	Daniel 1	(1)	255	34,304	18.1	98.4	44.1	10,985	Coal	16,867	11,171	376,843	1,832,510	5.34	108.64
30									Oil-S	707	139,799	4,154	97,266		137.58
31	Daniel 2	(1)	255	3,046	1.6	43.2	33.2	15,510	Coal	2,093	11,286	47,243	227,393	7.47	108.64
32									Oil-S	675	139,799	3,965	92,832		137.53
33	Total		2,477	583,725	31.7	85.9	47.9	9,490				5,457,066	24,719,399	4.23	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
-	Coal Additive - Crist	47,726	
709	Inventory Adj - Coal, Scholz	61,625	
(2,754)	Inventory Adj - Coal, Smith	(300,263)	
	Recoverable Fuel	24,524,428	

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./ct/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(763)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,014	0	0	0.00	0.00
3									Gas-S	0	1,014	0	0		0.00
4									Oil-S	0	137,552	0	0		0.00
5	Crist 5		75	33,927	62.8	100.0	62.8	11,439	Coal	16,552	11,723	388,082	1,652,587	4.87	99.84
6				-					Gas-G	0	1,014	0	0	0.00	0.00
7									Gas-S	1,251	1,014	1,269	13,077		10.45
8									Oil-S	130	137,552	750	16,029		123.30
9	Crist 6		299	93,076	43.3	98.3	64.9	11,344	Coal	44,845	11,772	1,055,821	4,477,335	4.81	99.84
10				233					Gas-G	2,564	1,014	2,600	26,795	11.50	10.45
11									Gas-S	5,468	1,014	5,544	57,129		10.45
12									Oil-S	5	137,552	28	590		118.00
13	Crist 7		475	65,500	19.4	95.6	52.7	11,327	Coal	31,461	11,791	741,915	3,141,111	4.80	99.84
14				843					Gas-G	9,413	1,014	9,545	98,361	11.67	10.45
15									Gas-S	440	1,014	446	4,599		10.45
16									Oil-S	27	137,552	154	3,282		121.56
17	Scholz 1		46	(220)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(147)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	38,293	32.8	78.0	46.0	11,070	Coal	18,452	11,487	423,916	1,974,090	5.16	106.99
22									Oil-S	284	138,243	1,648	36,965		130.16
23	Smith 2		195	40,486	28.8	94.3	39.3	11,097	Coal	19,602	11,460	449,286	2,097,160	5.18	106.99
24									Oil-S	55	138,243	320	7,170		130.36
25	Smith 3		558	199,607	49.7	65.6	85.6	7,645	Gas-G	1,503,375	1,015	1,525,926	7,945,205	3.98	5.28
26	Smith A	(2)	36	67	0.3	100.0	85.5	16,985	Oil	197	137,322	1,138	21,611	32.26	109.70
27	Other Generation			6,482									217,562	3.36	0.00
28	Perdido			1,796					Landfill Gas				52,342	2.91	0.00
29	Daniel 1	(1)	255	66,200	36.1	99.0	49.6	10,407	Coal	31,428	10,961	688,947	3,435,332	5.19	109.31
30									Oil-S	506	139,381	2,962	65,486		129.42
31	Daniel 2	(1)	255	46,049	25.1	89.4	49.2	10,936	Coal	22,937	10,978	503,596	2,507,238	5.44	109.31
32									Oil-S	549	139,381	3,214	71,050		129.42
33	Total		2,477	591,429	33.2	88.1	56.6	9,958				5,807,107	27,922,106	4.72	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
	Coal Additive - Crist	151,969	
	Recoverable Fuel	28,070,017	

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(878)	0.0	100.0	0.0	0	Coal	0.0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,013	0	0	0.00	0.00
3									Gas-S	0	1,013	0	0		0.00
4									Oil-S	0	137,552	0	0		0.00
5	Crist 5		75	39,632	72.8	100.0	72.8	10,963	Coal	18,540	11,717	434,467	1,860,201	4.69	100.33
6				1,001					Gas-G	10,817	1,013	10,958	151,377	15.12	13.99
7									Gas-S	2,230	1,013	2,259	31,203		13.99
8									Oil-S	78	137,552	446	9,647		123.68
9	Crist 6		299	(2,430)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,013	0	0	0.00	0.00
11									Gas-S	0	1,013	0	0		0.00
12									Oil-S	0	137,552	0	0		0.00
13	Crist 7		475	192,625	54.5	99.8	54.5	10,712	Coal	87,864	11,742	2,063,427	8,815,903	4.58	100.34
14				0					Gas-G	0	1,013	0	0	0.00	0.00
15									Gas-S	0	1,013	0	0		0.00
16									Oil-S	10	137,552	58	1,259		125.90
17	Scholz 1		46	(231)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	137,647	0	0		0.00
19	Scholz 2		46	(158)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	137,647	0	0		0.00
21	Smith 1		162	57,214	47.5	100.0	47.5	10,823	Coal	26,646	11,620	619,246	2,825,076	4.94	106.02
22									Oil-S	78	138,243	453	10,168		130.36
23	Smith 2		195	(731)	0.0	74.2	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,243	0	0		0.00
25	Smith 3		558	282,805	68.1	98.0	83.1	7,060	Gas-G	2,022,292	1,016	1,996,549	10,960,834	3.88	5.42
26	Smith A	(2)	36	61	0.2	100.0	82.9	17,803	Oil	188	137,322	1,086	20,813	34.12	110.71
27	Other Generation			6,488									215,343	3.32	0.00
28	Perdido			2,152					Landfill Gas				63,553	2.95	0.00
29	Daniel 1	(1)	255	9,715	5.1	87.2	40.4	13,768	Coal	5,939	11,262	133,756	653,398	6.73	110.02
30									Oil-S	332	138,434	1,933	43,030		129.61
31	Daniel 2	(1)	255	40,254	21.2	82.0	47.6	10,850	Coal	19,625	11,128	436,762	2,159,234	5.36	110.02
32									Oil-S	347	138,434	2,018	44,928		129.48
33	Total		2,477	627,519	34.1	94.3	44.7	9,216				5,703,418	27,865,967	4.44	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
	Coal Additive - Crist	117,276	
(13,079)	Inventory Adjustment - Daniel	(1,405,600)	
	Inventory Adjustment - Gas Smith	(106,075)	
	Recoverable Fuel	26,467,509	

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2013

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2013	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	16,879	32.6	100.0	54.6	11,322	Coal	8,289.0	11,528	191,112	826,494	4.90	99.71
2				713					Gas-G	7,961	1,014	8,072	62,920	8.82	7.90
3									Gas-S	1,479	1,014	1,500	11,692		7.91
4									Oil-S	126	137,552	729	15,762		125.10
5	Crist 5		75	19,661	36.6	91.4	63.4	11,385	Coal	9,572	11,691	223,844	954,551	4.86	99.72
6				99					Gas-G	1,114	1,014	1,130	8,807	8.90	7.91
7									Gas-S	0	1,014	0	0		0.00
8									Oil-S	92	137,552	534	11,554		125.59
9	Crist 6		299	53,758	25.0	76.0	57.2	11,747	Coal	27,737	11,384	631,514	2,765,627	5.14	99.71
10				5					Gas-G	55	1,014	56	437	8.75	7.95
11									Gas-S	16,674	1,014	16,907	131,789		7.90
12									Oil-S	34	137,552	196	4,244		124.82
13	Crist 7		475	198,703	58.1	100.0	58.1	10,717	Coal	91,681	11,614	2,129,565	9,141,439	4.60	99.71
14				90					Gas-G	948	1,014	961	7,491	8.32	7.90
15									Gas-S	0	1,014	0	0		0.00
16									Oil-S	29	137,552	170	3,675		126.72
17	Scholz 1		46	2,376	7.2	99.8	38.4	14,274	Coal	1,465	11,571	33,914	127,418	5.36	86.97
18									Oil-S	17	137,647	98	2,205		129.71
19	Scholz 2		46	3,221	9.7	100.0	52.9	13,907	Coal	1,925	11,636	44,795	167,357	5.20	86.94
20									Oil-S	24	137,647	133	3,000		125.00
21	Smith 1		162	64,545	55.3	100.0	55.3	10,876	Coal	30,199	11,623	702,001	3,177,932	4.92	105.23
22									Oil-S	89	138,176	517	11,191		125.74
23	Smith 2		195	41,570	29.6	97.2	41.4	11,146	Coal	19,992	11,588	463,325	2,103,791	5.06	105.23
24									Oil-S	410	138,176	2,378	51,460		125.51
25	Smith 3		556	264,554	66.1	87.0	77.7	7,335	Gas-G	1,910,026	1,016	1,940,586	10,198,244	3.85	5.34
26	Smith A	(2)	32	36	0.2	89.5	75.0	20,111	Oil	126	137,322	724	13,875	38.54	110.12
27	Other Generation			6,320									223,621	3.54	0.00
28	Perdido			1,984					Landfill Gas				59,830	3.02	0.00
29	Daniel 1	(1)	255	96,718	52.7	98.7	53.1	10,417	Coal	45,352	11,107	1,007,477	5,020,605	5.19	110.70
30									Oil-S	146	137,591	844	18,234		124.89
31	Daniel 2	(1)	255	100,720	54.9	97.9	55.2	10,505	Coal	47,632	11,107	1,058,064	5,272,953	5.24	110.70
32									Oil-S	274	137,591	1,585	34,231		124.93
33	Total		2,471	871,952	49.0	93.2	59.9	9,799				8,462,731	40,432,429	4.64	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
N/A	Daniel Railcar Track Deprec.	(4,059)	
	Coal Additive - Crist	209,003	
	Recoverable Fuel	40,637,373	

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: JULY 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	13,753	24.6	97.0	55.8	11,917	Coal	6,820	12,017	163,897	661,309	4.81	96.97
2	4							Gas - G						
3	Crist 5	75	25,313	45.4	97.0	62.0	11,433	Coal	12,042	12,017	289,416	1,167,768	4.61	96.97
4	5							Gas - G						
5	Crist 6	299	68,040	30.6	91.8	43.7	11,506	Coal	32,574	12,017	782,873	3,158,820	4.64	96.97
6	6							Gas - G						
7	Crist 7	475	237,339	67.2	91.8	73.7	10,820	Coal	106,847	12,017	2,567,902	10,361,247	4.37	96.97
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				56,112	2.67	N/A
10	Scholz 1	46	2,232	6.5	98.2	39.1	13,007	Coal	1,230	11,798	29,032	106,983	4.79	86.98
11	Scholz 2	46	2,060	6.0	99.0	39.1	13,509	Coal	1,179	11,798	27,828	102,546	4.98	86.98
12	Smith 1	162	71,235	59.1	98.6	78.3	10,495	Coal	31,602	11,828	747,576	3,511,025	4.93	111.10
13	Smith 2	195	64,126	44.2	98.0	59.4	10,749	Coal	29,138	11,828	689,295	3,237,306	5.05	111.10
14	Smith 3	556	346,965	83.9	98.3	85.5	7,249	Gas	2,441,784	1,030	2,515,037	11,974,654	3.45	4.90
15	Smith A (CT)	32	64	0.3	99.1	0.0	14,063	Oil	154	139,400	900	17,427	27.23	113.16
16	Other Generation		8,572					Gas				286,819	3.35	N/A
17	Daniel 1 (1)	255	65,047	34.3	98.2	63.0	10,301	Coal	29,811	11,238	670,059	3,303,481	5.08	110.81
18	Daniel 2 (1)	255	105,283	55.5	97.9	62.4	10,392	Coal	48,676	11,238	1,094,084	5,393,982	5.12	110.81
19	Gas,BL							Gas	0	0	0	0	N/A	N/A
20	Ltr. Oil							Oil	1,094	139,400	6,408	138,937	N/A	127.00
21		2,471	1,012,129	55.1	96.2	66.5	10,212				9,584,307	43,478,416	4.30	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: AUGUST 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	4,520	8.1	97.0	58.5	11,982	Coal	2,249	12,041	54,160	216,357	4.79	96.20
2	4							Gas - G						
3	Crist 5	75	29,310	52.5	97.0	63.2	11,450	Coal	13,936	12,041	335,602	1,340,652	4.57	96.20
4	5							Gas - G						
5	Crist 6	299	41,799	18.8	91.8	43.8	11,575	Coal	20,091	12,041	483,831	1,932,791	4.62	96.20
6	6							Gas - G						
7	Crist 7	475	183,734	52.0	91.8	73.4	10,801	Coal	82,404	12,041	1,984,453	7,927,423	4.31	96.20
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				56,112	2.67	N/A
10	Scholz 1	46	3,464	10.1	98.2	39.1	13,013	Coal	1,910	11,798	45,078	166,111	4.80	86.97
11	Scholz 2	46	2,358	6.9	99.0	39.1	13,515	Coal	1,351	11,798	31,868	117,434	4.98	86.92
12	Smith 1	162	84,714	70.3	98.7	78.3	10,496	Coal	37,195	11,952	889,139	4,214,652	4.98	113.31
13	Smith 2	195	70,234	48.4	98.0	62.0	10,726	Coal	31,514	11,952	753,342	3,570,954	5.08	113.31
14	Smith 3	556	350,803	84.8	98.2	86.4	7,255	Gas	2,470,947	1,030	2,545,076	12,028,635	3.43	4.87
15	Smith A (CT)	32	32	0.1	99.1	100.0	14,063	Oil	77	139,400	450	8,724	27.26	113.30
16	Other Generation		8,572					Gas				286,819	3.35	N/A
17	Daniel 1 (1)	255	83,830	44.2	97.8	62.9	10,315	Coal	38,498	11,230	864,678	4,293,443	5.12	111.52
18	Daniel 2 (1)	255	67,780	35.7	98.0	61.6	10,421	Coal	31,447	11,230	706,307	3,507,073	5.17	111.52
19	Gas,BL							Gas	0	0	0	0	N/A	N/A
20	Ltr. Oil							Oil	1,094	139,400	6,408	138,719	N/A	126.80
21		2,471	933,250	50.8	96.1	68.2	10,347				8,700,392	39,805,899	4.27	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	2,649	4.9	97.0	0.0	11,967	Coal	1,315	12,055	31,701	126,537	4.78	96.23
2	4							Gas - G						
3	Crist 5	75	16,223	30.0	97.0	56.1	11,570	Coal	7,785	12,055	187,702	749,228	4.62	96.24
4	5							Gas - G						
5	Crist 6	299	82,754	38.4	91.8	42.0	11,556	Coal	39,664	12,055	956,307	3,817,177	4.61	96.24
6	6							Gas - G						
7	Crist 7	475	106,429	31.1	91.8	65.5	10,930	Coal	48,247	12,055	1,163,234	4,643,140	4.36	96.24
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				54,268	2.67	N/A
10	Scholz 1	46	1,134	3.4	98.2	0.0	13,017	Coal	626	11,798	14,761	54,395	4.80	86.89
11	Scholz 2	46	2,034	6.1	99.0	0.0	13,515	Coal	1,165	11,798	27,489	101,298	4.98	86.95
12	Smith 1	162	56,268	48.2	98.6	73.0	10,511	Coal	24,491	12,074	591,421	2,828,199	5.03	115.48
13	Smith 2	195	37,221	26.5	98.0	47.5	10,817	Coal	16,673	12,074	402,620	1,925,346	5.17	115.48
14	Smith 3	556	336,671	84.1	98.2	85.0	7,246	Gas	2,368,540	1,030	2,439,596	11,572,251	3.44	4.89
15	Smith A (CT)	32	0	0.0	99.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,296					Gas				277,584	3.35	N/A
17	Daniel 1 (1)	255	120,725	65.8	98.2	67.0	10,213	Coal	54,934	11,222	1,232,937	6,172,385	5.11	112.36
18	Daniel 2 (1)	255	119,348	65.0	98.0	66.5	10,281	Coal	54,670	11,222	1,227,016	6,142,745	5.15	112.36
19	Gas,BL							Gas	0	0	0	0	N/A	N/A
20	Ltr. Oil							Oil	1,094	139,400	6,408	138,589	N/A	126.68
21		2,471	891,783	50.1	96.1	60.8	10,857				8,281,192	38,603,142	4.33	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: OCTOBER 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	3,816	6.8	95.6	55.5	12,009	Coal	1,899	12,065	45,827	183,347	4.80	96.55
2	4							Gas - G						
3	Crist 5	75	18,660	33.4	95.6	55.9	11,584	Coal	8,958	12,065	216,164	864,845	4.63	96.54
4	5							Gas - G						
5	Crist 6	299	79,437	35.7	88.6	41.7	11,565	Coal	38,073	12,065	918,692	3,675,563	4.63	96.54
6	6							Gas - G						
7	Crist 7	475	89,512	25.3	88.7	60.6	11,093	Coal	41,149	12,065	992,916	3,972,525	4.44	96.54
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				56,112	2.67	N/A
10	Scholz 1	46	2,160	6.3	97.4	0.0	13,017	Coal	1,192	11,798	28,116	103,609	4.80	86.92
11	Scholz 2	46	162	0.5	99.0	0.0	13,512	Coal	93	11,798	2,189	8,068	4.98	86.75
12	Smith 1	162	84,943	70.5	98.6	73.7	10,475	Coal	36,576	12,164	889,816	4,271,822	5.03	116.79
13	Smith 2	195	23,487	16.2	98.0	56.0	10,702	Coal	10,332	12,164	251,359	1,206,720	5.14	116.79
14	Smith 3	557	264,434	63.8	76.1	84.9	7,112	Gas	1,825,897	1,030	1,880,674	9,612,974	3.64	5.26
15	Smith A (CT)	36	0	0.0	99.1	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				191,391	3.35	N/A
17	Daniel 1 (1)	255	25,025	13.2	99.9	32.8	10,861	Coal	12,121	11,212	271,787	1,375,936	5.50	113.52
18	Daniel 2 (1)	255	76,045	40.1	99.8	46.2	10,536	Coal	35,731	11,212	801,219	4,056,213	5.33	113.52
19	Gas,BL							Gas	0	0	0	0	N/A	N/A
20	Ltr. Oil							Oil	1,094	139,400	6,408	138,490	N/A	126.59
21		2,476	675,501	36.7	90.5	56.5	9,779				6,305,167	29,717,615	4.40	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: NOVEMBER 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	95.6	55.9	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	24,146	44.7	95.6	55.7	11,589	Coal	11,590	12,072	279,823	1,123,837	4.65	96.97
4	5							Gas - G						
5	Crist 6	299	72,414	33.6	88.6	41.8	11,560	Coal	34,669	12,072	837,074	3,361,890	4.64	96.97
6	6							Gas - G						
7	Crist 7	475	72,753	21.3	88.6	53.9	11,259	Coal	33,925	12,072	819,094	3,289,676	4.52	96.97
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				54,268	2.67	N/A
10	Scholz 1	46	0	0.0	97.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	49.5	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	61,436	52.7	98.6	71.2	10,492	Coal	26,315	12,248	644,590	3,114,259	5.07	118.35
13	Smith 2	195	21,617	15.4	98.0	56.2	10,703	Coal	9,445	12,248	231,359	1,117,783	5.17	118.35
14	Smith 3	557	320,680	79.9	98.2	81.2	7,080	Gas	2,204,437	1,030	2,270,570	11,086,866	3.46	5.03
15	Smith A (CT)	36	0	0.0	99.0		N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,536					Gas				185,235	3.35	N/A
17	Daniel 1 (1)	255	6,261	3.4	98.5	45.4	11,577	Coal	3,235	11,202	72,483	370,518	5.92	114.53
18	Daniel 2 (1)	255	6,170	3.4	99.2	35.3	11,637	Coal	3,205	11,202	71,801	367,032	5.95	114.52
19	Gas,BL							Gas	0	0	0	0	N/A	N/A
20	Ltr. Oil							Oil	1,063	139,400	6,223	134,445	N/A	126.48
21		2,476	593,044	33.3	94.3	54.4	9,003				5,233,017	24,205,809	4.08	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: DECEMBER 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	18,300	32.8	95.6	55.6	11,986	Coal	9,080	12,079	219,350	880,774	4.81	97.00
2	4							Gas - G						
3	Crist 5	75	4,733	8.5	95.6	55.9	11,599	Coal	2,272	12,079	54,899	220,441	4.66	97.03
4	5							Gas - G						
5	Crist 6	299	74,179	33.3	88.6	41.8	11,565	Coal	35,511	12,079	857,875	3,444,698	4.64	97.00
6	6							Gas - G						
7	Crist 7	475	109,059	30.9	88.6	53.9	11,113	Coal	50,170	12,079	1,212,012	4,866,692	4.46	97.00
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				56,112	2.67	N/A
10	Scholz 1	46	2,188	6.4	97.4	39.1	13,006	Coal	1,206	11,798	28,458	104,868	4.79	86.96
11	Scholz 2	46	0	0.0	73.5	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	75,424	62.6	98.6	71.8	10,485	Coal	32,127	12,308	790,821	3,834,696	5.08	119.36
13	Smith 2	195	11,277	7.8	98.0	56.0	10,710	Coal	4,906	12,308	120,773	585,629	5.19	119.37
14	Smith 3	558	354,659	85.4	98.3	88.2	7,080	Gas	2,437,745	1,030	2,510,877	12,294,905	3.47	5.04
15	Smith A (CT)	40	0	0.0	99.1	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				191,391	3.35	N/A
17	Daniel 1 (1)	255	44,987	23.7	98.3	49.5	10,727	Coal	21,554	11,195	482,568	2,490,488	5.54	115.55
18	Daniel 2 (1)	255	0	0.0	98.9	55.9	N/A	Coal	0	0	0	0	N/A	N/A
19	Gas,BL							Gas	0	0	0	0	N/A	N/A
20	Ltr. Oil							Oil	817	139,400	4,786	103,416	N/A	126.58
21		2,481	702,626	38.1	94.7	59.2	9,637				6,282,419	29,074,110	4.14	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2013 - DECEMBER 2013

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	61,181	9.3	95.2	33.1	12,190	Coal	31,404	11,874	745,800	3,072,089	5.02	97.82
2	4							Gas - G	8,665	1,014	8,785	67,895		
3	Crist 5	75	321,236	48.8	97.4	62.8	11,114	Coal	151,052	11,818	3,570,125	14,931,257	4.65	98.85
4	5							Gas - G	53,985	1,014	54,737	409,529		
5	Crist 6	298	558,631	21.3	93.0	31.4	11,679	Coal	273,164	11,942	6,523,987	26,633,901	4.77	97.50
6	6							Gas - G	22,142	120	2,656	27,232		
7	Crist 7	474	1,808,379	43.4	94.5	59.2	10,622	Coal	810,080	11,856	19,209,168	79,876,774	4.42	98.60
8	7							Gas - G	497,861	1,016	505,804	1,994,355		
9	Perdido		24,630					Landfill Gas				689,900	2.80	N/A
10	Scholz 1	46	20,791	5.1	98.9	17.7	13,631	Coal	12,226	11,590	283,393	1,063,089	5.11	86.95
11	Scholz 2	46	8,983	2.2	93.3	10.9	14,936	Coal	5,713	11,742	134,169	496,703	5.53	86.94
12	Smith 1	162	758,221	53.3	97.5	61.3	10,685	Coal	342,976	11,811	8,101,821	38,353,587	5.06	111.83
13	Smith 2	195	337,102	19.7	96.1	38.6	10,895	Coal	156,269	11,751	3,672,652	17,427,152	5.17	111.52
14	Smith 3	562	3,585,834	72.7	89.9	84.4	7,192	Gas - G	25,255,309	1,021	25,788,530	122,283,045	3.41	4.84
15	Smith A (CT)	36	455	0.1	98.6	43.7	16,468	Oil - G	1,287	138,621	7,493	141,340	31.06	109.82
16	Other Generation		80,118									2,680,586	3.35	N/A
17	Daniel 1 (1)	255	551,429	24.6	97.5	42.3	10,521	Coal	260,840	11,121	5,801,535	29,067,215	5.27	111.44
18	Daniel 2 (1)	255	563,805	25.2	81.1	42.8	10,546	Coal	266,016	11,176	5,946,092	29,633,863	5.26	111.40
19	Gas,BL							Gas	10,554	3,138	33,114	280,828	N/A	26.61
20	Ltr. Oil							Oil	14,136	139,089	82,579	1,827,348	N/A	129.27
21		2,479	8,680,795	39.9	92.8	54.1	9,998				80,472,440	370,957,688	4.27	

Notes:
(1) Represents Gulf's 50% Ownership

Inventory Adjustments		$	units
COAL	Crist	(28,018)	0
	Scholz	61,625	709
	Smith	(289,232)	(2,754)
	Daniel	(1,405,600)	(13,079)
OIL	Crist	0	0
	Scholz	0	0
	Smith	0	0
GAS	Smith	(106,075)	0
Crist Coal Additive		1,014,818	N/A
Daniel Railcar Track Deprec.		(24,354)	
	Total Adjustments	$ (776,836)	$ (15,124)
Total Fuel Burned Cost		**$ 370,180,851**	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	178	714	1,964	1,953	0	1,974	1,091	1,091	1,091	1,091	1,063	815	13,025
3	UNIT COST ($/BBL)	133.28	140.97	132.64	125.25	0.00	122.67	126.29	126.29	126.29	126.29	126.33	126.49	127.77
4	AMOUNT ($)	23,724	100,651	260,500	244,615	3,976	242,151	137,787	137,787	137,787	137,787	134,284	103,092	1,664,141
5	*BURNED :*													
6	UNITS (BBL)	376	1,592	2,435	1,612	881	1,302	1,094	1,094	1,094	1,094	1,063	817	14,454
7	UNIT COST ($/BBL)	125.30	136.17	134.65	129.05	129.10	125.41	127.00	126.80	126.68	126.59	126.48	126.58	129.34
8	AMOUNT ($)	47,114	216,783	327,866	208,032	113,739	163,285	138,937	138,719	138,589	138,490	134,445	103,416	1,869,415
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	5,770	4,892	4,421	4,762	3,881	4,553	4,550	4,547	4,544	4,541	4,541	4,539	
11	UNIT COST ($/BBL)	129.57	129.09	127.60	126.15	126.50	125.15	124.98	124.86	124.76	124.69	124.66	124.64	
12	AMOUNT ($)	747,628	631,496	564,131	600,713	490,950	569,816	568,666	567,734	566,932	566,229	566,068	565,744	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL													
14	*PURCHASES :*													
15	UNITS (TONS)	163,071	113,561	161,628	127,313	174,655	156,445	212,300	196,500	166,500	158,771	146,500	166,927	1,944,171
16	UNIT COST ($/TON)	100.73	107.02	98.47	104.30	103.74	101.22	102.44	105.13	108.55	109.92	111.66	109.64	105.09
17	AMOUNT ($)	16,426,795	12,153,754	15,914,867	13,278,125	18,118,769	15,835,755	21,748,002	20,657,223	18,073,338	17,452,372	16,357,555	18,301,813	204,318,368
18	*BURNED :*													
19	UNITS (TONS)	135,335	105,358	163,849	185,277	145,535	283,844	299,919	260,595	249,570	186,124	122,384	156,826	2,294,616
20	UNIT COST ($/TON)	102.54	102.77	101.89	104.09	102.44	104.14	103.38	104.71	106.42	105.94	104.14	104.75	104.11
21	AMOUNT ($)	13,877,149	10,827,460	16,694,827	19,284,854	14,908,212	29,558,167	31,004,467	27,286,890	26,560,450	19,718,648	12,744,995	16,428,286	238,894,405
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	965,944	974,146	971,926	913,962	943,082	815,682	728,063	663,968	580,898	553,545	577,661	587,762	
24	UNIT COST ($/TON)	105.00	105.48	104.92	105.00	105.16	104.77	104.66	104.78	105.15	106.25	108.07	109.40	
25	AMOUNT ($)	101,428,262	102,754,556	101,974,596	95,967,867	99,178,424	85,456,013	76,199,548	69,569,881	61,082,769	58,816,493	62,429,053	64,302,580	
26	DAYS SUPPLY:	46	46	46	43	45	39	35	32	28	26	28	28	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	GAS (Reported on a MMBTU and $ basis)													
27	*PURCHASES :*													
28	UNITS (MMBTU)	2,386,744	2,670,579	1,640,513	1,566,280	2,062,896	1,973,145	2,644,120	2,545,076	2,406,971	1,848,049	2,270,570	2,347,752	26,362,695
29	UNIT COST ($/MMBTU)	3.90	3.80	4.60	5.70	5.54	5.26	4.45	4.73	4.74	5.11	4.92	4.99	4.75
30	AMOUNT ($)	9,316,407	10,150,149	7,542,083	8,926,606	11,422,098	10,374,888	11,755,067	12,048,308	11,411,057	9,447,702	11,165,427	11,718,585	125,278,377
31	*BURNED :*													
32	UNITS (MMBTU)	2,386,742	2,680,234	1,640,513	1,545,328	2,009,766	1,969,213	2,515,037	2,545,076	2,439,596	1,880,674	2,270,570	2,510,877	26,393,626
33	UNIT COST ($/MMBTU)	3.94	3.81	4.37	5.27	5.49	5.29	4.76	4.73	4.74	5.11	4.88	4.90	4.73
34	AMOUNT ($)	9,392,127	10,220,323	7,170,190	8,145,166	11,037,340	10,421,380	11,974,654	12,028,635	11,572,251	9,612,974	11,086,866	12,294,905	124,956,811
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	781,308	771,653	771,653	792,605	845,735	849,667	978,750	978,750	946,125	913,500	913,500	750,375	10,293,621
37	UNIT COST ($/MMBTU)	3.90	3.85	4.34	5.21	5.33	5.26	4.34	4.36	4.34	4.31	4.40	4.59	4.52
38	AMOUNT ($)	3,043,783	2,973,609	3,345,502	4,126,943	4,511,701	4,466,209	4,245,622	4,265,295	4,104,101	3,938,829	4,017,390	3,441,070	46,479,054
	OTHER - C.T. OIL													
39	*PURCHASES :*													
40	UNITS (BBL)	356	0	0	715	0	(126)	154	77	0	0	0	0	1,176
41	UNIT COST ($/BBL)	133.13	0.00	0.00	120.16	0.00	110.12	126.49	126.49	0.00	0.00	0.00	0.00	131.94
42	AMOUNT ($)	47,394	0	0	85,912	6,513	(13,875)	19,480	9,740	0	0	0	0	155,164
43	*BURNED :*													
44	UNITS (BBL)	215	173	157	197	188	126	154	77	0	0	0	0	1,287
45	UNIT COST ($/BBL)	108.11	107.93	108.11	109.70	110.71	110.12	113.16	113.30	0.00	0.00	0.00	0.00	109.82
46	AMOUNT ($)	23,244	18,672	16,974	21,611	20,813	13,875	17,427	8,724	0	0	0	0	141,340
47	*ENDING INVENTORY :*													
48	UNITS (BBL)	6,096	5,923	5,766	6,284	6,096	5,845	5,845	5,845	5,845	5,845	5,845	5,845	
49	UNIT COST ($/BBL)	108.18	108.19	108.19	109.50	110.53	110.53	110.88	111.06	111.06	111.06	111.06	111.06	
50	AMOUNT ($)	659,464	640,792	623,818	688,119	673,819	646,069	648,122	649,138	649,138	649,138	649,138	649,138	
51	DAYS SUPPLY:	3	3	3	3	3	3	3	3	3	3	3	3	

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)		
			KWH		¢ / KWH			
	MONTH	TOTAL KWH	WHEELED FROM OTHER	KWH FROM OWN	FUEL	TOTAL	TOTAL $ FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
	JANUARY							
1	Other Power Sales	434,660,661	1,787,080	432,873,581	1.92	2.06	8,338,042	8,973,263
2	Economy Sales	5,142,160	0	5,142,160	2.49	3.08	127,906	158,267
3	Gain on Economy Sales	0	0	0	0.00	0.00	9,801	9,801
4	TOTAL ACTUAL SALES	439,802,821	1,787,080	438,015,741	1.93	2.08	8,475,749	9,141,331
	FEBRUARY							
1	Other Power Sales	510,650,921	130,891,835	379,759,086	1.93	2.08	9,843,351	10,644,281
2	Economy Sales	7,233,862	0	7,233,862	2.74	3.15	198,560	228,208
3	Gain on Economy Sales	0	0	0	0.00	0.00	25,889	25,889
4	TOTAL ACTUAL SALES	517,884,783	130,891,835	386,992,948	1.94	2.10	10,067,800	10,898,378
	MARCH							
1	Other Power Sales	477,702,856	138,615,200	339,087,656	1.82	1.96	8,677,020	9,367,387
2	Economy Sales	5,558,488	0	5,558,488	3.07	4.04	170,775	224,742
3	Gain on Economy Sales	0	0	0	0.00	0.00	(384)	(384)
4	TOTAL ACTUAL SALES	483,261,344	138,615,200	344,646,144	1.83	1.98	8,847,411	9,591,745
	APRIL							
1	Other Power Sales	246,709,456	241,002,918	5,706,538	1.80	1.87	4,439,680	4,620,031
2	Economy Sales	3,655,509	0	3,655,509	3.57	3.99	130,573	145,888
3	Gain on Economy Sales	0	0	0	0.00	0.00	8,782	8,782
4	TOTAL ACTUAL SALES	250,364,965	241,002,918	9,362,047	1.83	1.91	4,579,035	4,774,701
	MAY							
1	Other Power Sales	259,546,886	115,976,619	143,570,267	1.90	1.98	4,922,235	5,147,333
2	Economy Sales	13,071,538	0	13,071,538	3.06	3.30	400,097	431,592
3	Gain on Economy Sales	0	0	0	0.00	0.00	52,332	52,332
4	TOTAL ACTUAL SALES	272,618,424	115,976,619	156,641,805	1.97	2.07	5,374,664	5,631,257
	JUNE							
1	Other Power Sales	397,151,331	159,537,825	237,613,506	2.07	2.19	8,207,997	8,687,377
2	Economy Sales	2,799,259	0	2,799,259	3.75	5.13	105,111	143,538
3	Gain on Economy Sales	0	0	0	0.00	0.00	(14,588)	(14,588)
4	TOTAL ACTUAL SALES	399,950,590	159,537,825	240,412,765	2.07	2.20	8,298,520	8,816,327

SCHEDULE E-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)		
			KWH		¢ / KWH			
	MONTH	TOTAL	WHEELED	KWH	FUEL	TOTAL	TOTAL $	
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	COST	COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JULY							
1	Other Power Sales	318,178,000	0	318,178,000	4.52	4.76	14,392,000	15,154,000
2	Economy Sales	4,339,000	0	4,339,000	4.29	4.56	186,000	198,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	78,000	78,000
4	TOTAL ESTIMATED SALES	322,517,000	0	322,517,000	4.54	4.78	14,656,000	15,430,000
	AUGUST							
1	Other Power Sales	280,190,000	0	280,190,000	4.71	4.99	13,200,000	13,990,000
2	Economy Sales	5,755,000	0	5,755,000	4.22	4.50	243,000	259,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	66,000	66,000
4	TOTAL ESTIMATED SALES	285,945,000	0	285,945,000	4.72	5.01	13,509,000	14,315,000
	SEPTEMBER							
1	Other Power Sales	183,312,000	0	183,312,000	4.21	4.51	7,713,000	8,263,000
2	Economy Sales	4,272,000	0	4,272,000	4.38	4.63	187,000	198,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	57,000	57,000
4	TOTAL ESTIMATED SALES	187,584,000	0	187,584,000	4.24	4.54	7,957,000	8,518,000
	OCTOBER							
1	Other Power Sales	205,646,000	0	205,646,000	3.08	3.44	6,338,000	7,067,000
2	Economy Sales	6,747,000	0	6,747,000	3.48	3.78	235,000	255,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	32,000	32,000
4	TOTAL ESTIMATED SALES	212,393,000	0	212,393,000	3.11	3.46	6,605,000	7,354,000
	NOVEMBER							
1	Other Power Sales	281,608,000	0	281,608,000	2.63	2.91	7,417,000	8,203,000
2	Economy Sales	7,930,000	0	7,930,000	2.76	3.06	219,000	243,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	26,000	26,000
4	TOTAL ESTIMATED SALES	289,538,000	0	289,538,000	2.65	2.93	7,662,000	8,472,000
	DECEMBER							
1	Other Power Sales	320,944,000	0	320,944,000	2.86	3.19	9,182,000	10,234,000
2	Economy Sales	8,633,000	0	8,633,000	3.12	3.43	269,000	296,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	65,000	65,000
4	TOTAL ESTIMATED SALES	329,577,000	0	329,577,000	2.89	3.21	9,516,000	10,595,000
	TOTAL							
1	Other Power Sales	3,916,300,111	787,811,477	3,128,488,634	2.62	2.82	102,670,325	110,350,672
2	Economy Sales	75,136,816	0	75,136,816	3.29	3.70	2,472,023	2,781,235
3	Gain on Economy Sales	0	0	0	0.00	0.00	405,832	405,832
4	TOTAL ESTIMATED SALES	3,991,436,927	787,811,477	3,203,625,450	2.64	2.84	105,548,180	113,537,739

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Total		23,435,000	0	0	0	2.68	2.68	628,657
FEBRUARY	Total		23,306,000	0	0	0	3.19	3.19	744,198
MARCH	Total		25,752,000	0	0	0	3.65	3.65	940,576
APRIL	Total		21,903,000	0	0	0	4.55	4.55	996,576
MAY	Total		21,895,000	0	0	0	4.09	4.09	895,427
JUNE	Total		17,483,000	0	0	0	4.87	4.87	851,224
JULY	Total		-	0	0	0	0.00	0.00	0
AUGUST	Total		-	0	0	0	0.00	0.00	0
SEPTEMBEI	Total		-	0	0	0	0.00	0.00	0
OCTOBER	Total		-	0	0	0	0.00	0.00	0
NOVEMBER	Total		-	0	0	0	0.00	0.00	0
DECEMBER	Total		-	0	0	0	0.00	0.00	0
TOTAL			133,774,000	0	0	0	3.78	3.78	5,056,658

SCHEDULE E-9
Page 1 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)
LINE MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
JANUARY				
1	Southern Co. Interchange	51,879,506	2.75	1,425,095
2	Other Purchases	594,891,736	2.53	15,034,021
3	ACTUAL TOTAL PURCHASES	646,771,242	2.54	16,459,116
FEBRUARY				
1	Southern Co. Interchange	24,113,729	2.70	651,782
2	Other Purchases	660,795,134	2.36	15,609,548
3	ACTUAL TOTAL PURCHASES	684,908,863	2.37	16,261,330
MARCH				
1	Southern Co. Interchange	39,763,176	3.31	1,316,085
2	Other Purchases	691,724,315	2.44	16,850,781
3	ACTUAL TOTAL PURCHASES	731,487,491	2.48	18,166,866
APRIL				
1	Southern Co. Interchange	103,056,122	3.64	3,746,558
2	Other Purchases	335,804,361	2.30	7,713,193
3	ACTUAL TOTAL PURCHASES	438,860,483	2.61	11,459,751
MAY				
1	Southern Co. Interchange	114,386,091	3.19	3,652,263
2	Other Purchases	459,750,181	2.75	12,625,966
3	ACTUAL TOTAL PURCHASES	574,136,272	2.84	16,278,229
JUNE				
1	Southern Co. Interchange	30,609,715	3.41	1,044,491
2	Other Purchases	652,089,992	2.54	16,575,003
3	ACTUAL TOTAL PURCHASES	682,699,707	2.58	17,619,494

SCHEDULE E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	8,044,300	4.48	360,000
2	Other Purchases	630,864,000	3.40	21,424,000
3	TOTAL ESTIMATED PURCHASES	638,908,300	3.41	21,784,000
	AUGUST			
1	Southern Co. Interchange	14,629,900	4.27	624,000
2	Other Purchases	648,808,000	3.44	22,313,000
3	TOTAL ESTIMATED PURCHASES	663,437,900	3.46	22,937,000
	SEPTEMBER			
1	Southern Co. Interchange	103,524,200	4.24	4,394,000
2	Other Purchases	329,651,000	3.53	11,637,000
3	TOTAL ESTIMATED PURCHASES	433,175,200	3.70	16,031,000
	OCTOBER			
1	Southern Co. Interchange	58,410,400	4.09	2,387,000
2	Other Purchases	421,749,000	3.17	13,369,000
3	TOTAL ESTIMATED PURCHASES	480,159,400	3.28	15,756,000
	NOVEMBER			
1	Southern Co. Interchange	28,184,800	3.30	931,000
2	Other Purchases	501,686,000	3.14	15,728,000
3	TOTAL ESTIMATED PURCHASES	529,870,800	3.14	16,659,000
	DECEMBER			
1	Southern Co. Interchange	29,045,900	3.78	1,098,000
2	Other Purchases	537,273,000	3.29	17,655,000
3	TOTAL ESTIMATED PURCHASES	566,318,900	3.31	18,753,000
	TOTAL FOR PERIOD			
1	Southern Co. Interchange	605,647,839	3.57	21,630,274
2	Other Purchases	6,465,086,719	2.89	186,534,512
3	TOTAL ACT/EST PURCHASES	7,070,734,558	2.94	208,164,786

Schedule CCE-1A

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD JANUARY 2014 - DECEMBER 2014

1. Estimated over/(under)-recovery, January 2013 - December 2013 (Schedule CCE-1b, line 15 + 18)	$ (2,263,786)
2. Final over/(under)-recovery, January 2012 - December 2012 (Exhibit RWD-1, Schedule CCA-1, filed March 1, 2012)	102,776
3. Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2014 - December 2014)	$ (2,161,010)
4. Jurisdictional kWh sales, January 2014 - December 2014	11,154,278,000
5. True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	0.0194

SCHEDULE CCE-1B

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2013 - December 2013

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Total
1	IIC Payments/(Receipts) ($)	419,141	(105,345)	341,687	42,050	(4,527)	(2,216)	0	0	0	0	0	0	690,790
2	Other Capacity Payments / (Receipts)	1,961,029	2,003,882	2,048,096	2,003,745	2,601,116	6,780,108	7,267,649	7,018,398	7,017,398	2,239,398	2,240,398	2,240,398	45,421,615
3	Transmission Revenue	(9,396)	(10,325)	(11,718)	(9,510)	(10,547)	(9,573)	(10,000)	(13,000)	(10,000)	(15,000)	(18,000)	(19,000)	(146,069)
4	Total Capacity Payments/(Receipts)	2,370,774	1,888,212	2,378,065	2,036,285	2,586,042	6,768,319	7,257,649	7,005,398	7,007,398	2,224,398	2,222,398	2,221,398	45,966,336
5	Jurisdictional %	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	2,289,538	1,823,512	2,296,580	1,966,511	2,497,430	6,536,400	7,008,963	6,765,355	6,767,287	2,148,178	2,146,247	2,145,281	44,391,282
7	Retail KWH Sales							1,198,377,000	1,181,726,000	1,034,929,000	865,410,000	762,800,000	852,320,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.397	0.397	0.397	0.397	0.397	0.397	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	3,092,021	2,777,430	3,146,584	2,854,644	3,482,025	4,346,407	4,757,557	4,691,452	4,108,668	3,435,678	3,028,316	3,383,710	43,104,492
10	Revenue Taxes (Line 9 x .00072) ($)	2,226	2,000	2,266	2,055	2,507	3,129	3,425	3,378	2,958	2,474	2,180	2,436	31,034
11	True-Up Provision ($)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(945,684)
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	3,010,988	2,696,623	3,065,511	2,773,782	3,400,711	4,264,471	4,675,325	4,609,267	4,026,903	3,354,397	2,947,329	3,302,467	42,127,774
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	721,450	873,111	768,931	807,271	903,281	(2,271,929)	(2,333,638)	(2,156,088)	(2,740,384)	1,206,219	801,082	1,157,186	(2,263,508)
14	Interest Provision ($)	(26)	34	100	147	197	137	15	(93)	(212)	(246)	(192)	(139)	(278)
15	Total Estimated True-Up for the Period January 2013 - December 2013 (Line 13 + Line 14) ($)													(2,263,786)
16	Beginning Balance True-Up & Interest Provision ($)	(842,908)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(822,178)	(2,899,552)	(5,561,341)	(4,276,561)	(3,396,864)	
17	True-Up Collected/(Refunded) ($)	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	
18	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	
19	End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(822,178)	(2,899,552)	(5,561,341)	(4,276,561)	(3,396,864)	(2,161,010)	

A B C D E F G H I J K L M N O P

Gulf Power Company
2013 Capacity Contracts

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other			
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2013	6/30/2013	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs
2013

Contract	January MW	January $	February MW	February $ [1]	March MW	March $	April MW	April $	May MW	May $ [1]	June MW	June $ [1]
Southern Intercompany Interchange	177.8	422,287	0.0	(102,074)	370.1	344,833	18.0	45,196	0.0	(1,079)	0.0	8,403
PPAs												
Coral Power,LLC												
Southern Power Company												
Shell Energy N.A. (U.S.), LP												
Other												
South Carolina PSA												
South Carolina Electric & Gas	0.0	0			0.0	0	0.0	0				
Total		2,380,170		1,898,537		2,389,783		2,045,794		2,596,589		6,777,892

(1) Southern Intercompany Interchange reserve sharing charge consists of prior month true up only

A B C D E F G H I J K L M N O P Q

Gulf Power Company
2013 Capacity Contracts

Schedule CCE-4
Page 2 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other			
South Carolina PSA	9/1/2003	-	Other
South Carolina Electric & Gas	1/1/2013	6/30/2013	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs
2013

Contract	July MW	July $	August MW	August $	September MW	September $	October MW	October $	November MW	November $	December MW	December $	Total $
Southern Intercompany Interchange	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	717,566
PPAs													
Coral Power,LLC													
Southern Power Company													
Shell Energy N.A. (U.S.), LP													
Total PPAs													45,441,114
Other													
South Carolina PSA													(38,374)
South Carolina Electric & Gas	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(7,902)
Total		7,267,649		7,018,398		7,017,398		2,239,398		2,240,398		2,240,398	46,112,404

Docket No. 130001-EI
2013 Estimated/Actual True-Up Filing
Exhibit RWD-2, Page 32 of 32

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

Line				(a) $	(b) kWh	(c) ¢ / kWh
1	Fuel Cost of System Net Generation		E-3	355,672,030	8,851,840,000	4.0181
2	Coal Car Investment					
3	Other Generation		E-3	3,254,676	81,428,000	3.9970
4	Hedging Settlement		E-2			
5	**Total Cost of Generated Power**	(Line 1 - 4)		358,926,706	8,933,268,000	4.0179
6	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			
7	Energy Cost of Schedule C & X Econ. Purch.		E-9			
8	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	173,773,123	5,470,006,000	3.1768
9	Energy Cost of Schedule E Economy Purch.		E-9			
10	Capacity Cost of Schedule E Economy Purchases		E-2			
11	Energy Payments to Qualifying Facilities		E-8			
12	**Total Cost of Purchased Power**	(Line 6 - 11)		173,773,123	5,470,006,000	3.1768
13	**Total Available kWh**	(Line 5 + 12)			14,403,274,000	
14	Fuel Cost of Economy Sales		E-6	(2,432,000)	(75,070,000)	3.2396
15	Gain on Economy Sales		E-6	(594,995)	0	N/A
16	Fuel Cost of Other Power Sales		E-6	(69,218,000)	(2,108,392,000)	3.2830
17	**Total Fuel Cost & Gains on Power Sales**	(Line 14 -16)		(72,244,995)	(2,183,462,000)	3.3087
18	Net Inadvertant Interchange					
19	**Total Fuel & Net Power Trans.**	(Line 5+12+17+18)		460,454,834	12,219,812,000	3.7681
20	Net Unbilled Sales *					
21	Company Use *			808,446	21,455,000	3.7681
22	T & D Losses *			26,114,139	693,032,000	3.7681
23	**System kWh Sales**			460,454,834	11,505,325,000	4.0021
24	Wholesale kWh Sales			14,049,252	351,047,000	4.0021
25	Jurisdictional kWh Sales			446,405,582	11,154,278,000	4.0021
25a	Jurisdictional Line Loss Multiplier			1.0015		1.0015
26	Jurisdictional kWh Sales Adjusted for Line Losses			447,075,190	11,154,278,000	4.0081
27	**True-Up ****			15,998,761	11,154,278,000	0.1434
28	**Total Jurisdictional Fuel Cost**			463,073,951	11,154,278,000	4.1515
29	Revenue Tax Factor					1.00072
30	Fuel Factor Adjusted For Revenue Taxes			463,407,364	11,154,278,000	4.1545
31	GPIF Reward/(Penalty) **			1,662,342	11,154,278,000	0.0149
32	Fuel Factor Adjusted for GPIF			465,069,706	11,154,278,000	4.1694
33	**Fuel Factor Rounded to Nearest .001(¢ / kWh)**					**4.169**

*For informational purposes only
** Calculation Based on Jurisdictional kWh Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 43
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION R.W. Dodd - RWD-3

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2014 - DECEMBER 2014

1.	Estimated over/(under)-recovery, January 2013 - December 2013 (Sch. E-1B, page 2, line C9)	($6,665,066)
2.	Final over/(under)-recovery, January 2012 - December 2012 (Exhibit RWD-1, Schedule 1, Line 3)	($9,333,695)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2014 - December 2014 (Schedule E1, Line 27)	(15,998,761)
4.	Jurisdictional kWh sales For the period: January 2014 - December 2014	11,154,278,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / kWh)	0.1434

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	23,612,216.88	21,601,356.61	24,302,567.18	27,852,455.30	26,252,165.97	40,413,751.45	$164,034,513.39
	1a	Fuel Cost of Hedging Settlement	2,013,400.00	2,166,655.00	793,231.00	403,524.00	493,084.00	916,010.00	$6,785,904.00
	2	Fuel Cost of Power Sold	(8,475,749.46)	(10,067,800.03)	(8,847,411.42)	(4,579,035.77)	(5,374,663.85)	(8,298,519.65)	($45,643,180.18)
	3	Fuel Cost of Purchased Power	16,459,115.59	16,261,329.94	18,166,866.50	11,459,751.39	16,278,229.43	17,619,494.27	$96,244,787.12
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities	628,657.17	744,198.26	940,575.93	996,575.97	895,426.55	851,224.12	$5,056,658.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	183,550.37	199,409.00	221,861.59	217,561.76	215,342.86	223,621.47	$1,261,347.05
	6	Adjustments to Fuel Cost *	6,952.10	79,735.13	13,168.04	16,269.98	(9,788.63)	15,967.75	$122,304.37
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	34,428,142.65	30,984,883.91	35,590,858.82	36,367,102.63	$38,749,796.33	$51,741,549.41	$227,862,333.75
B	1	Jurisdictional KWH Sales	778,963,209	705,542,522	793,160,952	730,244,171	883,344,861	1,078,668,799	4,969,924,514
	2	Non-Jurisdictional KWH Sales	24,917,444	22,515,414	24,361,046	21,950,706	25,381,308	29,535,698	148,661,616
	3	TOTAL SALES (Lines B1 + B2)	803,880,653	728,057,936	817,521,998	752,194,877	908,726,169	1,108,204,497	5,118,586,130
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.9004%	96.9075%	97.0201%	97.0818%	97.2069%	97.3348%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	29,539,374.46	26,749,927.96	30,090,473.26	27,703,808.92	33,545,795.79	40,974,608.87	$188,603,989.26
	2	True-Up Provision	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	$13,212,708.00
	2a	Incentive Provision	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	($519,954.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$31,654,833.46	$28,865,386.96	$32,205,932.26	$29,819,267.92	$35,661,254.79	$43,090,067.87	$201,296,743.26
	4	Fuel & Net Power Transactions (Line A7)	34,428,142.65	30,984,883.91	35,590,858.82	36,367,102.63	38,749,796.33	51,741,549.41	$227,862,333.75
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	33,411,049.45	30,071,716.39	34,582,082.25	35,358,796.60	37,723,976.98	50,438,077.44	$221,585,699.11
	6	Over/(Under) Recovery (Line C3-C5)	(1,756,215.99)	(1,206,329.43)	(2,376,149.99)	(5,539,528.68)	(2,062,722.19)	(7,348,009.57)	($20,288,955.85)
	7	Interest Provision	876.53	902.97	557.82	85.64	(297.67)	(628.17)	$1,497.12
	8	Adjustments (2)	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2013 - JUNE 2013**							($20,287,458.73)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note 1: Revenues for July through December based on the current approved 2013 Fuel Factor excluding revenue taxes of: 3.7999
Note 2: Satisfaction of Peabody judgement

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

				JULY PROJECTION	AUGUST PROJECTION	SEPTEMBER PROJECTION	OCTOBER PROJECTION	NOVEMBER PROJECTION	DECEMBER PROJECTION	TOTAL PERIOD
				(a)	(a)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		43,191,597.00	39,519,080.00	38,325,558.00	29,526,224.00	24,020,574.00	28,882,719.00	$367,500,265.39
	1a	Fuel Cost of Hedging Settlement		0.00	0.00	0.00	0.00	0.00	0.00	$6,785,904.00
	2	Fuel Cost of Power Sold		(14,656,000.00)	(13,509,000.00)	(7,957,000.00)	(6,605,000.00)	(7,662,000.00)	(9,516,000.00)	($105,548,180.18)
	3	Fuel Cost of Purchased Power		21,784,000.00	22,937,000.00	16,031,000.00	15,756,000.00	16,659,000.00	18,753,000.00	$208,164,787.12
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$5,056,658.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		286,819.00	286,819.00	277,584.00	191,391.00	185,235.00	191,391.00	$2,680,586.05
	6	Adjustments to Fuel Cost *		0.00	0.00	0.00	0.00	0.00	0.00	$122,304.37
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$50,606,416.00	$49,233,899.00	$46,677,142.00	$38,868,615.00	$33,202,809.00	$38,311,110.00	$484,762,324.75
B	1	Jurisdictional KWH Sales		1,198,377,000	1,181,726,000	1,034,929,000	865,410,000	762,800,000	852,320,000	10,865,486,514
	2	Non-Jurisdictional KWH Sales		34,430,000	34,820,000	30,495,000	26,329,000	24,784,000	28,961,000	328,480,616
	3	TOTAL SALES (Lines B1 + B2)		1,232,807,000	1,216,546,000	1,065,424,000	891,739,000	787,584,000	881,281,000	11,193,967,130
	4	Jurisdictional % Of Total Sales (Line B1/B3)		97.2072%	97.1378%	97.1378%	97.0475%	96.8532%	96.7138%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	45,536,697.38	44,903,982.01	39,325,895.51	32,884,403.89	28,985,363.34	32,387,001.68	$412,627,333.06
	2	True-Up Provision		2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,118.00	2,202,120.00	$26,425,418.00
	2a	Incentive Provision		(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,659.00)	(86,662.00)	($1,039,911.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$47,652,156.38	$47,019,441.01	$41,441,354.51	$34,999,862.89	$31,100,822.34	$34,502,459.68	$438,012,840.06
	4	Fuel & Net Power Transactions (Line A7)		50,606,416.00	49,233,899.00	46,677,142.00	38,868,615.00	33,202,809.00	38,311,110.00	$484,762,324.75
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)		49,266,869.63	47,896,463.43	45,409,160.56	37,777,600.67	32,206,219.98	37,107,708.50	$471,249,721.88
	6	Over/(Under) Recovery (Line C3-C5)		(1,614,713.25)	(877,022.42)	(3,967,806.05)	(2,777,737.78)	(1,105,397.64)	(2,605,248.82)	($33,236,881.81)
	7	Interest Provision		412.71	240.33	9.12	(269.63)	(476.82)	(679.72)	$733.11
	8	Adjustments	(2)	26,571,082.26	0.00	0.00	0.00	0.00	0.00	$26,571,082.26
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2013 - DECEMBER 2013**								($6,665,066.44)

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note 1: Revenues for July through December based on the current approved 2013 Fuel Factor excluding revenue taxes of: 3.7999
Note 2: Satisfaction of Peabody judgement

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2013 - JUNE 2013 / ESTIMATED FOR JULY 2013 - DECEMBER 2013

		DOLLARS				kWh				¢/kWh			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation	367,500,265	358,100,519	9,399,746	2.62	8,600,677,000	8,710,307,000	(109,630,000)	(1.26)	4.2729	4.1112	0.1617	3.93
1a	Fuel Cost of Hedging Settlement	6,785,904	0	6,785,904	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4	Other Generation	2,680,586	1,814,318	866,268	47.75	80,118,000	50,524,000	29,594,000	58.57	3.3458	3.5910	(0.2452)	(6.83)
5	Adjustments to Fuel Cost ***	122,304	0	122,304	100.00	0	0				0.0000		
6	TOTAL COST OF GENERATED POWER	377,089,060	359,914,837	17,174,223	4.77	8,680,795,000	8,760,831,000	(80,036,000)	(0.91)	4.3439	4.1082	0.2357	5.74
7	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
8	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
9	Energy Cost of Other Economy Purchases (Nonbroker)	208,164,787	185,816,000	22,348,787	12.03	7,070,734,558	6,164,950,000	905,784,558	14.69	2.9440	3.0141	(0.0701)	(2.33)
10	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
12	Energy Payments to Qualifying Facilities	5,056,658	0	5,056,658	100.00	133,774,000	0	133,774,000	100.00	3.7800	0.0000	3.7800	100.00
13	TOTAL COST OF PURCHASED POWER	213,221,445	185,816,000	27,405,445	14.75	7,204,508,558	6,164,950,000	1,039,558,558	16.86	2.9596	3.0141	(0.0545)	(1.81)
14	Total Available kWh (Line 6 + Line 13)	590,310,505	545,730,837	44,579,668	8.17	15,885,303,558	14,925,781,000	959,522,558	6.43	3.7161	3.6563	0.0598	1.64
15	Fuel Cost of Economy Sales	(2,472,023)	(2,428,000)	(44,023)	1.81	(75,136,816)	(77,479,000)	2,342,184	(3.02)	3.2900	3.1338	0.1562	4.98
16	Gain on Economy Sales	(405,832)	(645,241)	239,409	(37.10)	0	0						
17	Fuel Cost of Other Power Sales	(102,670,325)	(73,242,000)	(29,428,325)	40.18	(3,916,300,111)	(2,449,607,000)	(1,466,693,111)	59.87	2.6218	2.9899	(0.3683)	(12.32)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(105,548,180)	(76,315,241)	(29,232,939)	38.31	(3,991,436,927)	(2,527,086,000)	(1,464,350,927)	57.95	2.6444	3.0199	(0.3755)	(12.43)
19	(LINES 15+16+17)												
20	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
21	**TOTAL FUEL & NET POWER TRANSACTIONS**	484,762,325	469,415,596	15,346,729	3.27	11,893,866,631	12,398,695,000	(504,828,369)	(4.07)	4.0757	3.7860	0.2897	7.65
	(LINES 14+18+20)												
22	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
23	Company Use *	844,359	820,767	23,592	2.87	20,716,904	21,679,000	(962,096)	(4.44)	4.0757	3.7860	0.2897	7.65
24	T & D Losses *	27,681,445	26,311,754	1,369,691	5.21	679,182,597	694,975,000	(15,792,403)	(2.27)	4.0757	3.7860	0.2897	7.65
25	TERRITORIAL (SYSTEM) SALES	484,762,325	469,415,596	15,346,729	3.27	11,193,967,130	11,682,041,000	(488,073,870)	(4.18)	4.3306	4.0183	0.3123	7.77
26	Wholesale Sales	14,225,075	14,983,638	(758,563)	(5.06)	328,480,616	372,885,000	(44,404,384)	(11.91)	4.3306	4.0183	0.3123	7.77
27	Jurisdictional Sales	470,537,250	454,431,958	16,105,292	3.54	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	4.3306	4.0183	0.3123	7.77
28	Jurisdictional Loss Multiplier	1.0015	1.0015										
29	Jurisdictional Sales Adj. for Line Losses (Line 27 x 1.0015)	471,249,722	455,113,606	16,136,116	3.55	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	4.3371	4.0243	0.3128	7.77
30	TRUE-UP **	(26,425,418)	(26,425,418)	0	0.00	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	(0.2432)	(0.2337)	(0.0095)	4.07
31	TOTAL JURISDICTIONAL FUEL COST	444,824,304	428,688,188	16,136,116	3.76	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	4.0939	3.7906	0.3033	8.00
32	Revenue Tax Factor									1.00072	1.00072		
33	Fuel Factor Adjusted for Revenue Taxes									4.0968	3.7933	0.3035	8.00
34	GPIF Reward / (Penalty) **	1,040,660	1,040,660	0	0.00	10,865,486,514	11,309,156,000	(443,669,486)	(3.92)	0.0096	0.0092	0.0004	(4.35)
35	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1064	3.8025	0.3039	7.99
36	**FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									4.106	3.803	0.3030	7.97

* Included for informational purposes only.

** ¢/kWh calculation based on jurisdictional kWh sales.

*** (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note: Amounts included in the Estimated/Actual column represent 6 months actual and 6 months estimate.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY TO BE INCLUDED IN THE PERIOD: JANUARY 2014 - DECEMBER 2014

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	1,662,342
	B. True-Up (Over)/Under Recovered	$	15,998,761
2.	Jurisdictional kWh sales For the period: January 2014 - December 2014		11,154,278,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		0.0149
	B. True-Up Factor		0.1434

SCHEDULE E-1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

		NET ENERGY FOR LOAD %
	On-Peak	29.11
	Off-Peak	70.89
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per kWh Sold	4.0021	4.8087	3.6708
Jurisdictional Loss Factor	1.0015	1.0015	1.0015
Jurisdictional Fuel Factor	4.0081	4.8159	3.6763
GPIF	0.0149	0.0149	0.0149
True-Up	0.1434	0.1434	0.1434
TOTAL	4.1664	4.9742	3.8346
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	4.1694	4.9778	3.8374
Recovery Factor Rounded to the Nearest .001 ¢/kWh	4.169	4.978	3.837

HOURS:	ON-PEAK	25.01%
	OFF-PEAK	74.99%
		100.00%

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2014 - DECEMBER 2014

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, RSVP, GS, GSD, GSDT, GSTOU, OSIII, SBS (1)	4.169	1.00773	4.201
B	LP, LPT, SBS (2)	4.169	0.98353	4.100
C	PX, PXT, RTP, SBS (3)	4.169	0.96591	4.027
D	OS-I/II	4.169	1.00777	4.155 *

		TOU
A	On-Peak	5.016
	Off-Peak	3.867
B	On-Peak	4.896
	Off-Peak	3.774
C	On-Peak	4.808
	Off-Peak	3.707
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	4.978	¢ / kWh	x	0.2501	=	1.245	¢ / kWh
	Off-Peak	3.837	¢ / kWh	x	0.7499	=	2.878	¢ / kWh
							4.123	¢ / kWh
			Line Loss Multiplier			x	1.00777	
							4.155	¢ / kWh

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a Contract Demand over 7,499 KW

SCHEDULE E-2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	34,310,715	26,290,149	27,845,727	27,024,566	36,441,994	32,103,571	37,938,908	36,711,598	31,656,329	20,799,856	19,525,342	25,023,275	355,672,030
1a	Other Generation	228,628	206,565	228,628	221,274	342,623	331,591	342,623	342,623	331,591	228,628	221,274	228,628	3,254,676
2	Fuel Cost of Power Sold	(9,270,000)	(8,709,000)	(9,226,000)	(1,498,000)	(7,799,000)	(3,472,000)	(6,738,000)	(7,709,000)	(6,066,595)	(878,600)	(4,062,800)	(6,816,000)	(72,244,995)
3	Fuel Cost of Purchased Power	14,028,362	12,834,398	13,869,415	9,301,691	11,662,300	16,844,326	17,803,980	17,773,359	15,487,692	15,246,816	13,692,969	15,227,815	173,773,123
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 5)	39,297,705	30,622,112	32,717,770	35,049,531	40,647,917	45,807,488	49,347,511	47,118,580	41,409,017	35,396,700	29,376,785	33,663,718	460,454,834
7	System kWh Sold	920,682,000	772,415,000	799,153,000	796,607,000	999,654,000	1,132,366,000	1,237,540,000	1,220,252,000	1,068,126,000	893,822,000	786,860,000	877,848,000	11,505,325,000
7a	Jurisdictional % of Total Sales	96.7638	96.7444	96.9069	96.9599	97.0528	97.1281	97.1481	97.0740	97.0634	96.9521	96.7364	96.5942	96.9488
8	Cost per kWh Sold (¢/kWh)	4.2683	3.9645	4.0941	4.3999	4.0662	4.0453	3.9875	3.8614	3.8768	3.9602	3.7334	3.8348	4.0021
8a	Jurisdictional Loss Multiplier	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015
8b	Jurisdictional Cost (¢/kWh)	4.2747	3.9704	4.1002	4.4065	4.0723	4.0514	3.9935	3.8672	3.8826	3.9661	3.7390	3.8406	4.0081
9	GPIF (¢/kWh) *	0.0155	0.0185	0.0179	0.0179	0.0143	0.0126	0.0115	0.0117	0.0134	0.0160	0.0182	0.0163	0.0149
10	True-Up (¢/kWh) *	0.1497	0.1784	0.1722	0.1726	0.1374	0.1212	0.1109	0.1126	0.1286	0.1538	0.1752	0.1572	0.1434
11	TOTAL	4.4399	4.1673	4.2903	4.5970	4.2240	4.1852	4.1159	3.9915	4.0246	4.1359	3.9324	4.0141	4.1664
12	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
13	Recovery Factor Adjusted for Taxes	4.4431	4.1703	4.2934	4.6003	4.2270	4.1882	4.1189	3.9944	4.0275	4.1389	3.9352	4.0170	4.1694
14	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	4.443	4.170	4.293	4.600	4.227	4.188	4.119	3.994	4.028	4.139	3.935	4.017	4.169

* CALCULATIONS BASED ON JURISDICTIONAL kWh SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	156,408	156,373	121,918	152,421	152,320	152,241	152,178	156,114	155,563	148,375	121,051	121,037	1,745,999
2	COAL	24,788,607	16,259,055	17,683,785	18,023,980	24,317,956	20,519,619	26,016,670	24,544,899	19,898,913	10,544,394	10,776,865	13,724,093	227,098,836
3	GAS - Generation	9,369,976	9,862,428	10,045,460	8,890,876	12,133,159	11,583,029	11,929,521	12,118,954	11,709,711	10,151,383	8,620,607	11,169,861	127,584,965
4	GAS (B.L.)	166,560	166,680	165,400	122,670	123,390	124,380	125,370	167,760	167,840	126,540	172,200	179,120	1,807,910
5	LANDFILL GAS	57,792	52,178	57,792	55,893	57,792	55,893	57,792	57,792	55,893	57,792	55,893	57,792	680,294
6	OIL - C.T.	0	0	0	0	0	0	0	8,702	0	0	0	0	8,702
7	TOTAL ($)	34,539,343	26,496,714	28,074,355	27,245,840	36,784,617	32,435,162	38,281,531	37,054,221	31,987,920	21,028,484	19,746,616	25,251,903	358,926,706
	SYSTEM NET GEN. (MWh)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	519,372	343,114	377,169	372,515	550,467	451,297	573,473	559,014	456,685	229,424	241,795	305,875	4,980,200
10	GAS	307,144	332,791	332,169	244,801	372,720	342,810	355,764	360,633	345,404	293,269	274,854	365,957	3,928,316
11	LANDFILL GAS	2,100	1,896	2,100	2,031	2,100	2,031	2,100	2,100	2,031	2,100	2,031	2,100	24,720
12	OIL - C.T.	0	0	0	0	0	0	0	32	0	0	0	0	32
13	TOTAL (MWH)	828,616	677,801	711,438	619,347	925,287	796,138	931,337	921,779	804,120	524,793	518,680	673,932	8,933,268
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	1,231	1,233	960	1,204	1,204	1,204	1,204	1,235	1,231	1,174	956	956	13,792
15	COAL (TON)	243,676	160,430	178,932	178,803	267,139	218,538	273,963	268,487	221,750	112,039	116,410	149,733	2,389,900
16	GAS-all (MCF) (1)	2,058,373	2,201,781	2,215,586	1,612,223	2,432,148	2,247,313	2,330,371	2,369,277	2,272,255	1,907,404	1,838,560	2,418,495	25,903,786
17	OIL - C.T. (BBL)	0	0	0	0	0	0	0	77	0	0	0	0	77
	BTUS BURNED (MMBtu)													
18	COAL + GAS B.L. + OIL B.L.	5,758,961	3,850,831	4,173,555	4,307,998	6,008,818	5,028,702	6,350,362	6,177,989	5,055,456	2,692,101	2,764,969	3,516,318	55,686,060
19	GAS-Generation (1)	2,080,124	2,227,834	2,242,054	1,630,590	2,475,113	2,284,733	2,370,282	2,400,355	2,300,423	1,934,626	1,853,717	2,451,050	26,250,901
20	OIL - C.T.	0	0	0	0	0	0	0	450	0	0	0	0	450
21	TOTAL (MMBtu) (1)	7,839,085	6,078,665	6,415,609	5,938,588	8,483,931	7,313,435	8,720,644	8,578,794	7,355,879	4,626,727	4,618,686	5,967,368	81,937,411

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWh)													
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	62.68	50.62	53.01	60.14	59.49	56.68	61.57	60.65	56.80	43.72	46.62	45.39	55.75
24	GAS-Generation	37.07	49.10	46.69	39.53	40.28	43.06	38.20	39.12	42.95	55.88	52.99	54.30	43.97
25	LANDFILL GAS	0.25	0.28	0.30	0.33	0.23	0.26	0.23	0.23	0.25	0.40	0.39	0.31	0.28
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST ($ / UNIT)													
28	LIGHTER OIL ($/BBL)	127.06	126.82	127.00	126.60	126.51	126.45	126.39	126.41	126.37	126.38	126.62	126.61	126.60
29	COAL ($/TON)	101.73	101.35	98.83	100.80	91.03	93.89	94.96	91.42	89.74	94.11	92.58	91.66	95.02
30	GAS + B.L. ($/MCF) (1)	4.52	4.46	4.51	5.45	4.90	5.06	5.03	5.04	5.08	5.27	4.66	4.60	4.87
31	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	113.01	0.00	0.00	0.00	0.00	113.01
	FUEL COST ($ / MMBtu)													
32	COAL + GAS B.L. + OIL B.L.	4.36	4.31	4.31	4.25	4.09	4.14	4.14	4.03	4.00	4.02	4.00	3.99	4.14
33	GAS-Generation (1)	4.39	4.33	4.38	5.32	4.76	4.92	4.89	4.91	4.95	5.13	4.53	4.46	4.74
34	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.34	0.00	0.00	0.00	0.00	19.34
35	TOTAL ($/MMBtu) (1)	4.37	4.32	4.33	4.54	4.29	4.38	4.34	4.27	4.30	4.48	4.22	4.18	4.33
	BTU BURNED (Btu / kWh)													
36	COAL + GAS B.L. + OIL B.L.	11,088	11,223	11,065	11,565	10,916	11,143	11,074	11,052	11,070	11,734	11,435	11,496	11,181
37	GAS-Generation (1)	6,901	6,800	6,868	6,815	6,797	6,830	6,827	6,818	6,824	6,728	6,883	6,804	6,824
38	OIL - C.T.	0	0	0	0	0	0	0	14,063	0	0	0	0	14,063
39	TOTAL (Btu/kWh) (1)	9,551	9,063	9,118	9,707	9,276	9,307	9,472	9,416	9,267	8,950	9,037	8,959	9,282
	FUEL COST (CENTS / kWh)													
40	COAL + GAS B.L. + OIL B.L.	4.83	4.83	4.76	4.91	4.47	4.61	4.59	4.45	4.43	4.72	4.58	4.58	4.63
41	GAS-Generation	3.05	2.96	3.02	3.63	3.26	3.38	3.35	3.36	3.39	3.46	3.14	3.05	3.25
42	LANDFILL GAS	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
43	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.19	0.00	0.00	0.00	0.00	27.19
44	TOTAL (¢/kWh)	4.17	3.91	3.95	4.40	3.98	4.07	4.11	4.02	3.98	4.01	3.81	3.75	4.02

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: JANUARY 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	1,968	3.5	83.4	54.7	12,797	Coal	1,042	12,087	25,184	100,624	5.11	96.57
2	4							Gas - G						
3	Crist 5	75	10,005	17.9	93.5	56.1	11,599	Coal	4,801	12,087	116,048	463,675	4.63	96.58
4	5							Gas - G						
5	Crist 6	299	79,194	35.6	97.0	41.9	12,353	Coal	40,470	12,087	978,287	3,908,790	4.94	96.58
6	6							Gas - G						
7	Crist 7	475	182,472	51.6	97.6	56.2	11,105	Coal	83,827	12,087	2,026,353	8,096,384	4.44	96.58
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	55,143	45.8	98.9	73.0	10,511	Coal	23,497	12,333	579,606	2,776,245	5.03	118.15
13	Smith 2	195	55,475	38.2	99.7	57.0	10,664	Coal	23,983	12,333	591,581	2,833,604	5.11	118.15
14	Smith 3	584	301,424	69.4	83.1	83.5	6,901	Gas	2,019,538	1,030	2,080,124	9,141,348	3.03	4.53
15	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				228,628	4.00	N/A
17	Daniel 1 (1)	255	83,200	43.9	96.0	57.0	10,539	Coal	41,529	10,557	876,844	4,155,259	4.99	100.06
18	Daniel 2 (1)	255	51,915	27.4	98.7	57.7	9,975	Coal	24,527	10,557	517,849	2,454,026	4.73	100.05
19	Gas,BL							Gas	38,835	1,030	40,000	166,560	N/A	4.29
20	Ltr. Oil							Oil	1,231	139,400	7,209	156,408	N/A	127.03
21		2,507	828,616	44.4	93.9	59.2	10,598				7,839,085	34,539,343	4.17	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: FEBRUARY 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	9,060	16.2	99.4	55.4	12,015	Coal	4,505	12,081	108,856	432,600	4.77	96.03
2	4							Gas - G						
3	Crist 5	75	14,225	25.5	99.9	55.5	11,626	Coal	6,845	12,081	165,385	657,249	4.62	96.02
4	5							Gas - G						
5	Crist 6	299	24,990	11.2	62.6	41.2	12,438	Coal	12,864	12,081	310,822	1,235,223	4.94	96.02
6	6							Gas - G						
7	Crist 7	475	153,062	43.3	97.8	55.0	11,144	Coal	70,596	12,081	1,705,717	6,778,611	4.43	96.02
8	7							Gas - G						
9	Perdido		1,896					Landfill Gas				52,178	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	2,160	6.3	100.0	0.0	13,515	Coal	1,237	11,798	29,192	107,573	4.98	86.96
12	Smith 1	162	44,357	36.8	99.0	70.6	10,528	Coal	18,858	12,381	466,990	2,285,604	5.15	121.20
13	Smith 2	195	45,105	31.1	99.7	56.0	10,850	Coal	19,763	12,381	489,387	2,395,222	5.31	121.20
14	Smith 3	584	327,623	75.4	98.8	84.2	6,800	Gas	2,162,946	1,030	2,227,834	9,655,863	2.95	4.46
15	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,168					Gas				206,565	4.00	N/A
17	Daniel 1 (1)	255	44,940	23.7	65.8	48.4	10,526	Coal	23,112	10,234	473,034	2,123,527	4.73	91.88
18	Daniel 2 (1)	255	5,215	2.7	24.9	63.9	10,399	Coal	2,650	10,234	54,230	243,446	4.67	91.87
19	Gas,BL							Gas	38,835	1,030	40,000	166,680	N/A	4.29
20	Ltr. Oil							Oil	1,233	139,400	7,218	156,373	N/A	126.84
21		2,507	677,801	36.3	83.6	58.6	9,684				6,078,665	26,496,714	3.91	

Notes:
(1) Represents Gulf's 50% Ownership

Docket No. 130001-EI
2014 Projection Filing
Exhibit RWD-3, Page 13 of 42

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: MARCH 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	2,934	5.3	99.4	55.9	11,995	Coal	1,457	12,080	35,193	138,862	4.73	95.31
2	4							Gas - G						
3	Crist 5	75	29,350	52.6	99.6	55.9	11,606	Coal	14,099	12,080	340,631	1,344,033	4.58	95.33
4	5							Gas - G						
5	Crist 6	299	46,815	21.0	87.6	42.0	12,346	Coal	23,923	12,080	577,982	2,280,553	4.87	95.33
6	6							Gas - G						
7	Crist 7	475	95,077	26.9	78.7	55.8	10,735	Coal	42,245	12,080	1,020,649	4,027,191	4.24	95.33
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	2,160	6.3	100.0	0.0	13,017	Coal	1,192	11,798	28,116	103,609	4.80	86.92
11	Scholz 2	46	2,160	6.3	100.0	0.0	13,515	Coal	1,237	11,798	29,192	107,573	4.98	86.96
12	Smith 1	162	83,559	69.3	99.1	72.4	10,608	Coal	35,712	12,410	886,394	4,397,521	5.26	123.14
13	Smith 2	195	11,717	8.1	99.7	56.2	10,513	Coal	4,963	12,410	123,185	611,138	5.22	123.14
14	Smith 3	557	326,449	78.8	99.0	79.5	6,868	Gas	2,176,751	1,030	2,242,054	9,816,832	3.01	4.51
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				228,628	4.00	N/A
17	Daniel 1 (1)	255	103,397	54.5	95.8	58.0	10,509	Coal	54,104	10,042	1,086,594	4,673,305	4.52	86.38
18	Daniel 2 (1)	255	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
19	Gas,BL							Gas	38,835	1,030	40,000	165,400	N/A	4.26
20	Ltr. Oil							Oil	960	139,400	5,619	121,918	N/A	127.05
21		2,476	711,438	38.6	83.3	52.2	10,651				6,415,609	28,074,355	3.95	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: APRIL 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	36.5	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	8,312	14.9	36.7	55.7	11,612	Coal	3,995	12,080	96,517	381,471	4.59	95.49
4	5							Gas - G						
5	Crist 6	299	82,838	37.2	96.8	41.9	12,765	Coal	43,769	12,080	1,057,422	4,179,327	5.05	95.49
6	6							Gas - G						
7	Crist 7	475	147,924	41.9	90.8	58.3	11,634	Coal	71,234	12,080	1,720,947	6,801,825	4.60	95.49
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				55,893	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	68,129	56.5	99.3	73.1	10,510	Coal	28,772	12,443	716,032	3,568,219	5.24	124.02
13	Smith 2	195	30,675	21.1	59.9	55.4	10,609	Coal	13,077	12,443	325,432	1,621,733	5.29	124.01
14	Smith 3	557	239,265	57.7	69.3	86.0	6,815	Gas	1,583,097	1,030	1,630,590	8,669,602	3.62	5.48
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,536					Gas				221,274	4.00	N/A
17	Daniel 1 (1)	255	34,567	18.2	67.4	58.4	10,230	Coal	17,907	9,874	353,625	1,467,353	4.24	81.94
18	Daniel 2 (1)	255	70	0.0	33.1	13.8	13,943	Coal	49	9,874	976	4,052	5.79	82.69
19	Gas,BL							Gas	29,126	1,030	30,000	122,670	N/A	4.21
20	Ltr. Oil							Oil	1,204	139,400	7,047	152,421	N/A	126.64
21		2,476	619,347	33.6	73.7	53.9	10,252				5,938,588	27,245,840	4.40	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: MAY 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	64.1	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	13,436	24.1	64.7	55.8	11,606	Coal	6,481	12,030	155,936	591,321	4.40	91.24
4	5							Gas - G						
5	Crist 6	299	53,969	24.3	96.8	41.9	11,432	Coal	25,643	12,030	616,970	2,339,595	4.34	91.24
6	6							Gas - G						
7	Crist 7	475	201,817	57.1	97.8	58.7	11,028	Coal	92,502	12,030	2,225,640	8,439,787	4.18	91.24
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	22,360	18.6	99.2	65.1	10,636	Coal	9,543	12,461	237,817	1,202,220	5.38	125.98
13	Smith 2	195	49,387	34.0	99.7	47.1	10,782	Coal	21,367	12,461	532,495	2,691,885	5.45	125.98
14	Smith 3	581	364,148	84.2	99.1	84.9	6,797	Gas	2,403,022	1,030	2,475,113	11,790,536	3.24	4.91
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,572					Gas				342,623	4.00	N/A
17	Daniel 1 (1)	255	106,273	56.0	97.3	61.9	10,562	Coal	56,865	9,869	1,122,453	4,612,862	4.34	81.12
18	Daniel 2 (1)	255	103,225	54.4	98.7	60.3	10,467	Coal	54,738	9,869	1,080,460	4,440,286	4.30	81.12
19	Gas,BL							Gas	29,126	1,030	30,000	123,390	N/A	4.24
20	Ltr. Oil							Oil	1,204	139,400	7,047	152,320	N/A	126.55
21		2,500	925,287	49.7	96.4	57.9	10,468				8,483,931	36,784,617	3.98	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: JUNE 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	99.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	13,562	24.3	99.6	55.8	11,902	Coal	6,700	12,046	161,413	615,926	4.54	91.93
4	5							Gas - G						
5	Crist 6	299	71,664	32.2	96.9	41.9	12,353	Coal	36,744	12,046	885,269	3,378,042	4.71	91.93
6	6							Gas - G						
7	Crist 7	475	157,597	44.6	97.8	60.7	10,976	Coal	71,797	12,046	1,729,789	6,600,593	4.19	91.93
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				55,893	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	49,010	40.7	99.3	70.9	10,607	Coal	20,836	12,475	519,846	2,653,652	5.41	127.36
13	Smith 2	195	28,160	19.4	99.7	46.9	11,009	Coal	12,426	12,475	310,009	1,582,500	5.62	127.35
14	Smith 3	556	334,514	80.9	99.2	84.3	6,830	Gas	2,218,187	1,030	2,284,733	11,251,438	3.36	5.07
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,296					Gas				331,591	4.00	N/A
17	Daniel 1 (1)	255	65,765	34.7	96.1	50.0	10,575	Coal	35,159	9,890	695,461	2,855,937	4.34	81.23
18	Daniel 2 (1)	255	65,539	34.5	98.6	51.1	10,526	Coal	34,876	9,890	689,868	2,832,969	4.32	81.23
19	Gas,BL							Gas	29,126	1,030	30,000	124,380	N/A	4.27
20	Ltr. Oil							Oil	1,204	139,400	7,047	152,241	N/A	126.49
21		2,471	796,138	43.3	98.4	56.2	10,128				7,313,435	32,435,162	4.07	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: JULY 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	99.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4							Gas - G						
3	Crist 5	75	18,434	33.0	99.6	55.9	11,996	Coal	9,171	12,056	221,132	842,553	4.57	91.87
4	5							Gas - G						
5	Crist 6	299	58,860	26.5	97.0	42.0	12,882	Coal	31,446	12,056	758,228	2,888,986	4.91	91.87
6	6							Gas - G						
7	Crist 7	475	229,791	65.0	97.7	66.8	10,843	Coal	103,337	12,056	2,491,625	9,493,543	4.13	91.87
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	88,919	73.8	99.2	74.7	10,594	Coal	38,531	12,224	942,012	4,635,617	5.21	120.31
13	Smith 2	195	42,340	29.2	99.7	48.8	10,971	Coal	19,000	12,224	464,509	2,285,837	5.40	120.31
14	Smith 3	556	347,192	83.9	99.1	84.7	6,827	Gas	2,301,245	1,030	2,370,282	11,586,898	3.34	5.04
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,572					Gas				342,623	4.00	N/A
17	Daniel 1 (1)	255	77,514	40.9	97.3	54.1	10,637	Coal	41,621	9,905	824,516	3,370,936	4.35	80.99
18	Daniel 2 (1)	255	57,615	30.4	98.7	54.1	10,610	Coal	30,857	9,905	611,293	2,499,198	4.34	80.99
19	Gas,BL							Gas	29,126	1,030	30,000	125,370	N/A	4.30
20	Ltr. Oil							Oil	1,204	139,400	7,047	152,178	N/A	126.44
21		2,471	931,337	50.7	98.5	58.6	10,317				8,720,644	38,281,531	4.11	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: AUGUST 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	10,318	18.5	99.4	59.1	11,859	Coal	5,068	12,072	122,366	447,051	4.33	88.21
2	4							Gas - G						
3	Crist 5	75	20,949	37.5	99.6	61.5	11,371	Coal	9,866	12,072	238,211	870,277	4.15	88.21
4	5							Gas - G						
5	Crist 6	299	84,681	38.1	97.0	44.5	12,092	Coal	42,410	12,072	1,023,965	3,740,943	4.42	88.21
6	6							Gas - G						
7	Crist 7	475	155,103	43.9	97.6	64.5	10,888	Coal	69,944	12,072	1,688,765	6,169,717	3.98	88.21
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	2,160	6.3	100.0	0.0	13,017	Coal	1,192	11,798	28,116	103,609	4.80	86.92
11	Scholz 2	46	2,160	6.3	100.0	0.0	13,515	Coal	1,237	11,798	29,192	107,573	4.98	86.96
12	Smith 1	162	82,143	68.2	99.2	74.2	10,602	Coal	36,343	11,981	870,882	4,076,505	4.96	112.17
13	Smith 2	195	52,616	36.3	99.7	60.1	10,795	Coal	23,703	11,981	567,984	2,658,672	5.05	112.17
14	Smith 3	556	352,061	85.1	99.1	85.9	6,818	Gas	2,330,442	1,030	2,400,355	11,776,331	3.34	5.05
15	Smith A (CT)	32	32	0.1	100.0	0.0	14,063	Oil	77	139,400	450	8,702	27.19	113.19
16	Other Generation		8,572					Gas				342,623	4.00	N/A
17	Daniel 1 (1)	255	80,875	42.6	97.3	63.3	10,360	Coal	42,247	9,916	837,860	3,418,761	4.23	80.92
18	Daniel 2 (1)	255	68,009	35.8	98.7	53.0	10,637	Coal	36,477	9,916	723,416	2,951,790	4.34	80.92
19	Gas,BL							Gas	38,835	1,030	40,000	167,760	N/A	4.32
20	Ltr. Oil							Oil	1,235	139,400	7,232	156,114	N/A	126.39
21		2,471	921,779	50.1	98.5	62.4	10,307				8,578,794	37,054,221	4.02	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	9,444	17.5	99.1	55.7	12,002	Coal	4,691	12,081	113,347	414,523	4.39	88.37
2	4							Gas - G						
3	Crist 5	75	4,738	8.8	99.6	54.9	11,652	Coal	2,285	12,081	55,207	201,898	4.26	88.36
4	5							Gas - G						
5	Crist 6	299	86,850	40.3	96.9	42.0	12,346	Coal	44,379	12,081	1,072,248	3,921,332	4.52	88.36
6	6							Gas - G						
7	Crist 7	475	118,980	34.8	61.9	61.7	10,950	Coal	53,922	12,081	1,302,830	4,764,597	4.00	88.36
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				55,893	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	42,763	36.7	99.3	66.7	10,559	Coal	19,026	11,866	451,536	2,094,184	4.90	110.07
13	Smith 2	195	39,188	27.9	99.7	47.1	11,005	Coal	18,172	11,866	431,268	2,000,183	5.10	110.07
14	Smith 3	556	337,108	84.2	99.1	85.0	6,824	Gas	2,233,420	1,030	2,300,423	11,378,120	3.38	5.09
15	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		8,296					Gas				331,591	4.00	N/A
17	Daniel 1 (1)	255	96,379	52.5	96.1	61.1	10,092	Coal	48,746	9,977	972,656	3,998,201	4.15	82.02
18	Daniel 2 (1)	255	58,343	31.8	98.5	61.7	10,441	Coal	30,529	9,977	609,155	2,503,994	4.29	82.02
19	Gas,BL							Gas	38,835	1,030	40,000	167,840	N/A	4.32
20	Ltr. Oil							Oil	1,231	139,400	7,209	155,563	N/A	126.35
21		2,471	804,120	45.2	91.4	60.2	10,517				7,355,879	31,987,920	3.98	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: OCTOBER 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	15,492	27.8	99.2	55.8	11,995	Coal	7,689	12,084	185,827	659,562	4.26	85.78
2	4							Gas - G						
3	Crist 5	75	16,750	30.0	100.0	55.7	12,032	Coal	8,338	12,084	201,531	715,301	4.27	85.79
4	5							Gas - G						
5	Crist 6	299	89,736	40.3	96.8	42.0	12,346	Coal	45,839	12,084	1,107,884	3,932,248	4.38	85.78
6	6							Gas - G						
7	Crist 7	475	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	61,715	51.2	99.2	71.1	10,666	Coal	27,971	11,767	658,248	3,003,825	4.87	107.39
13	Smith 2	195	36,467	25.1	99.5	56.2	10,848	Coal	16,810	11,767	395,598	1,805,258	4.95	107.39
14	Smith 3	557	287,549	69.3	82.9	83.6	6,728	Gas	1,878,278	1,030	1,934,626	9,922,755	3.45	5.28
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				228,628	4.00	N/A
17	Daniel 1 (1)	255	4,947	2.6	59.4	38.8	11,673	Coal	2,934	9,842	57,748	232,978	4.71	79.41
18	Daniel 2 (1)	255	4,317	2.3	98.7	37.6	11,209	Coal	2,458	9,842	48,389	195,223	4.52	79.42
19	Gas,BL							Gas	29,126	1,030	30,000	126,540	N/A	4.34
20	Ltr. Oil							Oil	1,174	139,400	6,876	148,375	N/A	126.34
21		2,476	524,793	28.5	72.2	44.2	8,999				4,626,727	21,028,484	4.01	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: NOVEMBER 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	26,070	48.3	99.3	55.7	12,002	Coal	12,946	12,084	312,892	1,125,320	4.32	86.92
2	4							Gas - G						
3	Crist 5	75	4,490	8.3	99.9	54.9	11,653	Coal	2,165	12,084	52,320	188,169	4.19	86.91
4	5							Gas - G						
5	Crist 6	299	81,579	37.9	96.9	0.0	11,823	Coal	39,908	12,084	964,506	3,468,858	4.25	86.92
6	6							Gas - G						
7	Crist 7	475	14,489	4.2	22.8	51.7	11,267	Coal	6,754	12,084	163,243	587,105	4.05	86.93
8	7							Gas - G						
9	Perdido		2,031					Landfill Gas				55,893	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	60,729	52.1	92.6	70.3	10,530	Coal	27,333	11,698	639,476	2,894,087	4.77	105.88
13	Smith 2	195	30,915	22.0	99.4	55.6	10,676	Coal	14,107	11,698	330,046	1,493,695	4.83	105.88
14	Smith 3	557	269,318	67.1	85.9	77.9	6,883	Gas	1,799,725	1,030	1,853,717	8,399,333	3.12	4.67
15	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,536					Gas				221,274	4.00	N/A
17	Daniel 1 (1)	255	23,523	12.8	81.6	47.1	10,921	Coal	13,197	9,733	256,890	1,019,631	4.33	77.26
18	Daniel 2 (1)	255	0	0.0	72.3	0.0	N/A	Coal	0	0	0	0	N/A	N/A
19	Gas,BL							Gas	38,835	1,030	40,000	172,200	N/A	4.43
20	Ltr. Oil							Oil	956	139,400	5,596	121,051	N/A	126.66
21		2,476	518,680	29.1	76.3	44.6	9,433				4,618,686	19,746,616	3.81	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: DECEMBER 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	19,608	35.1	99.4	55.9	11,995	Coal	9,736	12,078	235,198	877,035	4.47	90.08
2	4							Gas - G						
3	Crist 5	75	4,868	8.7	100.0	55.5	11,626	Coal	2,343	12,078	56,593	211,031	4.34	90.07
4	5							Gas - G						
5	Crist 6	299	71,539	32.2	97.0	41.9	12,353	Coal	36,583	12,078	883,719	3,295,320	4.61	90.08
6	6							Gas - G						
7	Crist 7	475	85,965	24.3	97.6	54.5	11,161	Coal	39,718	12,078	959,459	3,577,749	4.16	90.08
8	7							Gas - G						
9	Perdido		2,100					Landfill Gas				57,792	2.75	N/A
10	Scholz 1	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
11	Scholz 2	46	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
12	Smith 1	162	4,946	4.1	67.3	67.9	10,549	Coal	2,239	11,650	52,175	235,606	4.76	105.23
13	Smith 2	195	76,890	53.0	99.7	56.4	10,844	Coal	35,785	11,650	833,795	3,765,154	4.90	105.22
14	Smith 3	584	360,237	82.9	99.0	83.7	6,804	Gas	2,379,660	1,030	2,451,050	10,941,233	3.04	4.60
15	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
16	Other Generation		5,720					Gas				228,628	4.00	N/A
17	Daniel 1 (1)	255	42,059	22.2	95.8	52.5	10,694	Coal	23,329	9,640	449,783	1,762,198	4.19	75.54
18	Daniel 2 (1)	255	0	0.0	86.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
19	Gas,BL							Gas	38,835	1,030	40,000	179,120	N/A	4.61
20	Ltr. Oil							Oil	956	139,400	5,596	121,037	N/A	126.64
21		2,507	673,932	36.1	94.9	52.3	9,530				5,967,368	25,251,903	3.75	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWh)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (Btu/kWh)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	94,894	14.4	89.8	37.3	12,001	Coal	47,134	12,081	1,138,863	4,195,577	4.42	89.01
2	4							Gas - G	0	0	0	0		
3	Crist 5	75	159,119	24.2	91.0	56.1	11,695	Coal	77,089	12,070	1,860,924	7,082,904	4.45	91.88
4	5							Gas - G	0	0	0	0		
5	Crist 6	299	832,715	31.7	93.5	38.6	12,294	Coal	423,978	12,073	10,237,302	38,569,217	4.63	90.97
6	6							Gas - G	0	0	0	0		
7	Crist 7	475	1,542,277	37.0	78.1	53.7	11,045	Coal	705,876	12,067	17,035,017	65,337,103	4.24	92.56
8	7							Gas - G	0	0	0	0		
9	Perdido		24,720					Landfill Gas				680,294	2.75	N/A
10	Scholz 1	46	4,320	1.1	100.0	0.0	13,017	Coal	2,384	11,794	56,232	207,218	4.80	86.92
11	Scholz 2	46	6,480	1.6	100.0	0.0	13,515	Coal	3,711	11,800	87,576	322,719	4.98	86.96
12	Smith 1	162	663,773	46.6	95.9	70.8	10,577	Coal	288,661	12,161	7,021,014	33,823,285	5.10	117.17
13	Smith 2	195	498,935	29.1	96.4	53.6	10,814	Coal	223,156	12,089	5,395,289	25,744,881	5.16	115.37
14	Smith 3	565	3,846,888	77.4	92.8	83.6	6,824	Gas - G	25,486,311	1,030	26,250,901	124,330,289	3.23	4.88
15	Smith A (CT)	36	32	0.0	100.0	0.0	14,063	Oil - G	2	5,853,205	450	8,702	27.19	4,753.90
16	Other Generation		81,428					Gas				3,254,676	4.00	N/A
17	Daniel 1 (1)	255	763,439	34.1	87.2	54.2	10,489	Coal	400,750	9,991	8,007,464	33,690,948	4.41	84.07
18	Daniel 2 (1)	255	414,248	18.5	75.6	37.8	10,466	Coal	217,161	9,983	4,335,636	18,124,984	4.38	83.46
19	Gas,BL							Gas	417,475	1,030	430,000	1,807,910	N/A	4.33
20	Ltr. Oil							Oil	13,790	139,406	80,743	1,745,999	N/A	126.61
21		2,484	8,933,268	40.9	88.4	55.0	10,130				81,937,411	358,926,706	4.02	

Notes:
(1) Represents Gulf's 50% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,091	1,091	815	1,063	1,063	1,063	1,063	1,091	1,091	1,034	815	815	12,093
3	UNIT COST ($/BBL)	125.29	125.29	125.42	125.28	125.28	125.28	125.28	125.29	125.29	125.27	125.42	125.42	125.31
4	AMOUNT ($)	136,637	136,637	102,232	133,163	133,163	133,163	133,163	136,637	136,637	129,493	102,232	102,232	1,515,389
5	*BURNED :*													
6	UNITS (BBL)	1,231	1,233	960	1,204	1,204	1,204	1,204	1,235	1,231	1,174	956	956	13,790
7	UNIT COST ($/BBL)	127.03	126.84	127.05	126.64	126.55	126.49	126.44	126.39	126.35	126.34	126.66	126.64	126.61
8	AMOUNT ($)	156,408	156,373	121,918	152,421	152,320	152,241	152,178	156,114	155,563	148,375	121,051	121,037	1,745,999
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	9,741	9,598	9,454	9,313	9,172	9,032	8,891	8,747	8,606	8,465	8,325	8,184	
11	UNIT COST ($/BBL)	127.87	127.71	127.58	127.44	127.31	127.18	127.05	126.92	126.80	126.67	126.55	126.43	
12	AMOUNT ($)	1,245,547	1,225,811	1,206,125	1,186,867	1,167,710	1,148,632	1,129,617	1,110,140	1,091,214	1,072,332	1,053,513	1,034,708	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL													
14	*PURCHASES :*													
15	UNITS (TONS)	200,590	200,850	204,817	198,750	255,717	227,742	265,913	277,553	202,675	127,283	129,993	148,186	2,440,069
16	UNIT COST ($/TON)	93.85	94.60	92.91	94.63	88.48	95.64	89.86	91.55	95.01	93.26	93.11	92.21	92.73
17	AMOUNT ($)	18,824,838	18,999,808	19,029,976	18,807,794	22,626,604	21,782,347	23,894,792	25,409,055	19,255,856	11,870,730	12,103,485	13,663,561	226,268,846
18	*BURNED :*													
19	UNITS (TONS)	243,676	160,430	178,932	178,803	267,139	218,538	273,963	268,487	221,750	112,039	116,410	149,733	2,389,900
20	UNIT COST ($/TON)	101.73	101.35	98.83	100.80	91.03	93.89	94.96	91.42	89.74	94.11	92.58	91.66	95.02
21	AMOUNT ($)	24,788,607	16,259,055	17,683,785	18,023,980	24,317,956	20,519,619	26,016,670	24,544,899	19,898,913	10,544,394	10,776,865	13,724,093	227,098,836
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	555,437	595,857	621,742	641,689	630,267	639,471	631,421	640,487	621,412	636,656	650,239	648,692	
24	UNIT COST ($/TON)	96.20	94.27	92.51	90.86	89.82	90.50	88.29	88.39	90.07	90.00	90.16	90.28	
25	AMOUNT ($)	53,430,372	56,171,125	57,517,316	58,301,130	56,609,778	57,872,506	55,750,628	56,614,784	55,971,727	57,298,063	58,624,683	58,564,151	
26	DAYS SUPPLY:	27	28	30	31	30	31	30	31	30	30	31	31	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GAS (1)													
31	*BURNED :*													
32	UNITS (MMBtu)	2,120,124	2,267,834	2,282,054	1,660,590	2,505,113	2,314,733	2,400,282	2,440,355	2,340,423	1,964,626	1,893,717	2,491,050	26,680,901
33	UNIT COST ($/MMBtu)	4.39	4.33	4.37	5.29	4.76	4.91	4.88	4.89	4.93	5.12	4.53	4.46	4.73
34	AMOUNT ($)	9,307,908	9,822,543	9,982,232	8,792,272	11,913,926	11,375,818	11,712,268	11,944,091	11,545,960	10,049,295	8,571,533	11,120,353	126,138,199
	OTHER - C.T. OIL													
39	*PURCHASES :*													
40	UNITS (BBL)	0	0	0	0	0	0	0	77	0	0	0	0	77
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	125.44	0.00	0.00	0.00	0.00	125.44
42	AMOUNT ($)	0	0	0	0	0	0	0	9,659	0	0	0	0	9,659
43	*BURNED :*													
44	UNITS (BBL)	0	0	0	0	0	0	0	77	0	0	0	0	77
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	113.01	0.00	0.00	0.00	0.00	113.01
46	AMOUNT ($)	0	0	0	0	0	0	0	8,702	0	0	0	0	8,702
47	*ENDING INVENTORY :*													
48	UNITS (BBL)	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	7,143	
49	UNIT COST ($/BBL)	113.05	113.05	113.05	113.05	113.05	113.05	113.05	113.19	113.19	113.19	113.19	113.19	
50	AMOUNT ($)	807,531	807,531	807,531	807,531	807,531	807,531	807,531	808,488	808,488	808,488	808,488	808,488	
51	DAYS SUPPLY:	4	4	4	4	4	4	4	4	4	4	4	4	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBtu's are not available due to contract specifications.

Docket No. 130001-EI
2014 Projection Filing
Exhibit RWD-3, Page 26 of 42

SCHEDULE E-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			kWh		(A)	(B)		
		TOTAL	WHEELED	kWh	¢ / kWh		TOTAL $	
	MONTH	kWh	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
	JANUARY							
1	Southern Co. Interchange	302,085,000	0	302,085,000	2.98	3.34	8,997,000	10,078,000
2	Economy Sales	6,833,000	0	6,833,000	3.00	3.32	205,000	227,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	68,000	68,000
4	TOTAL ESTIMATED SALES	308,918,000	0	308,918,000	3.00	3.36	9,270,000	10,373,000
	FEBRUARY							
5	Southern Co. Interchange	293,142,000	0	293,142,000	2.87	3.22	8,420,000	9,452,000
6	Economy Sales	7,726,000	0	7,726,000	2.89	3.24	223,000	250,000
7	Gain on Economy Sales	0	0	0	0.00	0.00	66,000	66,000
8	TOTAL ESTIMATED SALES	300,868,000	0	300,868,000	2.89	3.25	8,709,000	9,768,000
	MARCH							
9	Southern Co. Interchange	316,651,000	0	316,651,000	2.84	3.22	9,006,000	10,202,000
10	Economy Sales	5,967,000	0	5,967,000	3.05	3.39	182,000	202,000
11	Gain on Economy Sales	0	0	0	0.00	0.00	38,000	38,000
12	TOTAL ESTIMATED SALES	322,618,000	0	322,618,000	2.86	3.24	9,226,000	10,442,000
	APRIL							
13	Southern Co. Interchange	36,418,000	0	36,418,000	3.54	3.97	1,289,000	1,447,000
14	Economy Sales	5,857,000	0	5,857,000	2.97	3.47	174,000	203,000
15	Gain on Economy Sales	0	0	0	0.00	0.00	35,000	35,000
16	TOTAL ESTIMATED SALES	42,275,000	0	42,275,000	3.54	3.99	1,498,000	1,685,000
	MAY							
17	Southern Co. Interchange	218,275,000	0	218,275,000	3.44	3.75	7,504,000	8,191,000
18	Economy Sales	6,408,000	0	6,408,000	3.85	4.21	247,000	270,000
19	Gain on Economy Sales	0	0	0	0.00	0.00	48,000	48,000
20	TOTAL ESTIMATED SALES	224,683,000	0	224,683,000	3.47	3.79	7,799,000	8,509,000
	JUNE							
21	Southern Co. Interchange	83,783,000	0	83,783,000	3.88	4.15	3,251,000	3,478,000
22	Economy Sales	4,601,000	0	4,601,000	3.74	4.13	172,000	190,000
23	Gain on Economy Sales	0	0	0	0.00	0.00	49,000	49,000
24	TOTAL ESTIMATED SALES	88,384,000	0	88,384,000	3.93	4.21	3,472,000	3,717,000

SCHEDULE E-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			kWh		(A)	(B)		
		TOTAL	WHEELED	kWh	¢ / kWh		TOTAL $	
	MONTH	kWh	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
	JULY							
1	Southern Co. Interchange	149,373,000	0	149,373,000	4.34	4.60	6,482,000	6,876,000
2	Economy Sales	4,339,000	0	4,339,000	4.10	4.47	178,000	194,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	78,000	78,000
4	TOTAL ESTIMATED SALES	153,712,000	0	153,712,000	4.38	4.65	6,738,000	7,148,000
	AUGUST							
5	Southern Co. Interchange	156,765,000	0	156,765,000	4.73	5.02	7,412,000	7,864,000
6	Economy Sales	5,756,000	0	5,756,000	4.01	4.34	231,000	250,000
7	Gain on Economy Sales	0	0	0	0.00	0.00	66,000	66,000
8	TOTAL ESTIMATED SALES	162,521,000	0	162,521,000	4.74	5.03	7,709,000	8,180,000
	SEPTEMBER							
9	Southern Co. Interchange	158,331,000	0	158,331,000	3.70	4.05	5,861,000	6,413,000
10	Economy Sales	4,273,000	0	4,273,000	3.67	4.05	157,000	173,000
11	Gain on Economy Sales	0	0	0	0.00	0.00	48,595	57,000
12	TOTAL ESTIMATED SALES	162,604,000	0	162,604,000	3.73	4.09	6,066,595	6,643,000
	OCTOBER							
13	Southern Co. Interchange	25,414,000	0	25,414,000	2.57	3.01	654,000	765,000
14	Economy Sales	6,747,000	0	6,747,000	2.95	3.38	199,000	228,000
15	Gain on Economy Sales	0	0	0	0.00	0.00	25,600	32,000
16	TOTAL ESTIMATED SALES	32,161,000	0	32,161,000	2.73	3.19	878,600	1,025,000
	NOVEMBER							
17	Southern Co. Interchange	140,885,000	0	140,885,000	2.72	3.07	3,830,000	4,328,000
18	Economy Sales	7,930,000	0	7,930,000	2.67	3.04	212,000	241,000
19	Gain on Economy Sales	0	0	0	0.00	0.00	20,800	26,000
20	TOTAL ESTIMATED SALES	148,815,000	0	148,815,000	2.73	3.09	4,062,800	4,595,000
	DECEMBER							
21	Southern Co. Interchange	227,270,000	0	227,270,000	2.87	3.19	6,512,000	7,255,000
22	Economy Sales	8,633,000	0	8,633,000	2.92	3.24	252,000	280,000
23	Gain on Economy Sales	0	0	0	0.00	0.00	52,000	65,000
24	TOTAL ESTIMATED SALES	235,903,000	0	235,903,000	2.89	3.22	6,816,000	7,600,000
	TOTAL							
25	Southern Co. Interchange	2,108,392,000	0	2,108,392,000	3.28	3.62	69,218,000	76,349,000
26	Economy Sales	75,070,000	0	75,070,000	3.24	3.61	2,432,000	2,708,000
27	Gain on Economy Sales	0	0	0	0.00	0.00	594,995	628,000
28	TOTAL ESTIMATED SALES	2,183,462,000	0	2,183,462,000	3.31	3.65	72,244,995	79,685,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / kWh		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL kWh PURCH.	kWh FOR OTHER UTILITIES	kWh FOR INTERRUPTIBLE	kWh FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				kWh			¢/kWh		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL kWh PURCHASED	FOR OTHER UTILITIES	kWh FOR INTERRUPTIBLE	kWh FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY		COG-1				None			
FEBRUARY		COG-1				None			
MARCH		COG-1				None			
APRIL		COG-1				None			
MAY		COG-1				None			
JUNE		COG-1				None			
JULY		COG-1				None			
AUGUST		COG-1				None			
SEPTEMBER		COG-1				None			
OCTOBER		COG-1				None			
NOVEMBER		COG-1				None			
DECEMBER		COG-1				None			
TOTAL			0			0			0

SCHEDULE E-9
Page 1 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL kWh PURCHASED	TRANSACTION COST ¢ / kWh	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	20,062,000	3.62	726,000
2	Economy Energy	1,492,000	3.22	48,000
3	Other Purchases	433,135,000	3.06	13,254,362
4	TOTAL ESTIMATED PURCHASES	454,689,000	3.09	14,028,362
	FEBRUARY			
5	Southern Co. Interchange	27,316,000	3.37	921,000
6	Economy Energy	3,023,000	3.31	100,000
7	Other Purchases	403,428,000	2.93	11,813,398
8	TOTAL ESTIMATED PURCHASES	433,767,000	2.96	12,834,398
	MARCH			
9	Southern Co. Interchange	11,506,000	4.12	474,000
10	Economy Energy	1,481,000	3.58	53,000
11	Other Purchases	437,955,000	3.05	13,342,415
12	TOTAL ESTIMATED PURCHASES	450,942,000	3.08	13,869,415
	APRIL			
13	Southern Co. Interchange	190,679,000	3.42	6,523,000
14	Economy Energy	3,086,000	3.37	104,000
15	Other Purchases	66,016,000	4.05	2,674,691
16	TOTAL ESTIMATED PURCHASES	259,781,000	3.58	9,301,691
	MAY			
17	Southern Co. Interchange	40,724,000	4.40	1,790,000
18	Economy Energy	2,122,000	4.48	95,000
19	Other Purchases	318,780,000	3.07	9,777,300
20	TOTAL ESTIMATED PURCHASES	361,626,000	3.22	11,662,300
	JUNE			
21	Southern Co. Interchange	79,203,000	4.47	3,541,000
22	Economy Energy	2,406,000	4.45	107,000
23	Other Purchases	423,231,000	3.12	13,196,326
24	TOTAL ESTIMATED PURCHASES	504,840,000	3.34	16,844,326

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

LINE	(1) MONTH	(2) TYPE & SCHEDULE	(3) TOTAL kWh PURCHASED	(4) TRANSACTION COST ¢ / kWh	(5) TOTAL $ FOR FUEL ADJ.
	JULY				
1		Southern Co. Interchange	42,850,000	4.29	1,837,000
2		Economy Energy	2,844,000	4.96	141,000
3		Other Purchases	509,939,000	3.10	15,825,980
4		TOTAL ESTIMATED PURCHASES	555,633,000	3.20	17,803,980
	AUGUST				
5		Southern Co. Interchange	56,066,000	4.20	2,357,000
6		Economy Energy	3,326,000	4.96	165,000
7		Other Purchases	494,988,000	3.08	15,251,359
8		TOTAL ESTIMATED PURCHASES	554,380,000	3.21	17,773,359
	SEPTEMBER				
9		Southern Co. Interchange	27,732,000	3.85	1,069,000
10		Economy Energy	1,857,000	4.42	82,000
11		Other Purchases	468,604,000	3.06	14,336,692
12		TOTAL ESTIMATED PURCHASES	498,193,000	3.11	15,487,692
	OCTOBER				
13		Southern Co. Interchange	202,749,000	3.61	7,323,000
14		Economy Energy	5,580,000	3.48	194,000
15		Other Purchases	243,116,000	3.18	7,729,816
16		TOTAL ESTIMATED PURCHASES	451,445,000	3.38	15,246,816
	NOVEMBER				
17		Southern Co. Interchange	47,741,000	3.16	1,508,000
18		Economy Energy	4,099,000	3.15	129,000
19		Other Purchases	404,277,000	2.98	12,055,969
20		TOTAL ESTIMATED PURCHASES	456,117,000	3.00	13,692,969
	DECEMBER				
21		Southern Co. Interchange	35,235,000	3.23	1,138,000
22		Economy Energy	3,291,000	3.28	108,000
23		Other Purchases	450,067,000	3.11	13,981,815
24		TOTAL ESTIMATED PURCHASES	488,593,000	3.12	15,227,815
	TOTAL FOR PERIOD				
25		Southern Co. Interchange	781,863,000	3.74	29,207,000
26		Economy Energy	34,607,000	3.83	1,326,000
27		Other Purchases	4,653,536,000	3.08	143,240,123
28		TOTAL ESTIMATED PURCHASES	5,470,006,000	3.18	173,773,123

SCHEDULE E-10

GULF POWER COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 kWh
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

	Current Approved Jan. 13 - Dec. 13 ($/1,000 kWh)	Proposed Jan. 14 - Dec. 14 ($/1,000 kWh)	Difference from Current ($)	Difference from Current (%)
Base Rate	$ 58.13	$ 58.13	$ -	0.0%
Fuel Cost Recovery	38.32	42.01	3.69	9.6%
Capacity Cost Recovery	4.67	6.80	2.13	45.6%
Energy Conservation Cost Recovery	2.26	2.26	-	0.0%
Environmental Cost Recovery	12.53	15.54	3.01	24.0%
Subtotal	$ 115.91	$ 124.74	$ 8.83	7.6%
Gross Receipts Tax	2.97	3.20	0.23	7.7%
Total	$ 118.88	$ 127.94	$ 9.06	7.6%

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2015

		TOTAL ¢ / kWh
2014	JANUARY	3.267
	FEBRUARY	3.267
	MARCH	3.267
	APRIL	3.856
	MAY	3.856
	JUNE	3.856
	JULY	3.856
	AUGUST	3.856
	SEPTEMBER	3.856
	OCTOBER	3.856
	NOVEMBER	3.267
	DECEMBER	3.267
2015	JANUARY	3.354
	FEBRUARY	3.354
	MARCH	3.354
	APRIL	3.731
	MAY	3.731
	JUNE	3.731
	JULY	3.731
	AUGUST	3.731
	SEPTEMBER	3.731
	OCTOBER	3.731
	NOVEMBER	3.354
	DECEMBER	3.354

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2014 - DECEMBER 2014

LINE	LINE DESCRIPTION	2011	2012	2013	2014	% Change 2011 to 2012	% Change 2012 to 2013	% Change 2013 to 2014
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	LIGHTER OIL (B.L.)	404,847	663,864	806,844	1,745,999	63.98	21.54	116.40
2	COAL	473,437,001	411,231,936	230,848,996	227,098,836	(13.14)	(43.86)	(1.62)
3	COAL at Scherer	0	0	0	0	0.00	0.00	0.00
4	GAS	147,491,326	131,747,551	125,616,386	124,330,289	(10.67)	(4.65)	(1.02)
5	GAS (B.L.)	0	0	0	1,807,910	0.00	0.00	100.00
6	LANDFILL GAS	638,895	685,856	704,503	680,294	7.35	2.72	(3.44)
7	OTHER - C.T.	0	0	123,790	8,702	0.00	100.00	(92.97)
8	OTHER GENERATION	2,528,728	2,453,961	1,814,318	3,254,676	(2.96)	(26.07)	79.39
9	TOTAL ($)	624,500,797	546,783,168	359,914,837	358,926,706	(12.44)	(34.18)	(0.27)
	SYSTEM NET GENERATION (MWh)							
10	COAL	9,701,804	8,417,818	4,624,257	4,980,200	(13.23)	(45.07)	7.70
11	GAS	3,517,639	3,428,937	4,059,172	3,846,888	(2.52)	18.38	(5.23)
12	LANDFILL GAS	25,363	26,440	26,366	24,720	4.25	(0.28)	(6.24)
13	OTHER - C.T.	0	0	512	32	0.00	100.00	(93.75)
14	OTHER GENERATION	50,524	50,618	50,524	81,428	0.19	(0.19)	61.17
15	TOTAL (MWH)	13,295,330	11,923,813	8,760,831	8,933,268	(10.32)	(26.53)	1.97
	UNITS OF FUEL BURNED							
16	LIGHTER OIL (BBL)	3,931	4,895	6,864	13,792	24.53	40.24	100.93
17	COAL (TON)	4,515,305	3,958,270	2,201,050	2,389,900	(12.34)	(44.39)	8.58
18	GAS (MCF)	23,780,440	23,659,285	28,342,618	25,903,786	(0.51)	19.79	(8.60)
19	OTHER - C.T. (BBL)	0	0	1,161	77	0.00	100.00	(93.37)
	BTUS BURNED (MMBtu)							
20	COAL + GAS B.L. + OIL B.L.	103,517,119	91,370,112	51,387,546	55,686,060	(11.73)	(43.76)	8.36
21	GAS - Generation	24,493,854	24,369,058	27,773,568	26,250,901	(0.51)	13.97	(5.48)
22	OTHER - C.T.	0	0	6,802	450	0.00	100.00	(93.38)
23	TOTAL (MMBtu)	128,010,973	115,739,170	79,167,916	81,937,411	(9.59)	(31.60)	3.50
	GENERATION MIX (% MWh)							
24	COAL + GAS B.L. + OIL B.L.	72.97	70.60	52.78	55.75	(3.25)	(25.24)	5.63
25	GAS - Generation	26.46	28.76	46.33	43.06	8.69	61.09	(7.06)
26	LANDFILL GAS	0.19	0.22	0.30	0.28	15.79	36.36	(6.67)
27	OTHER - C.T.	0.00	0.00	0.01	0.00	0.00	100.00	(100.00)
28	OTHER GENERATION	0.38	0.42	0.58	0.91	10.53	38.10	56.90
29	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
30	LIGHTER OIL B.L. ($/BBL)	103.00	135.63	117.55	126.60	31.68	(13.33)	7.70
31	COAL ($/TON)	104.85	103.89	104.88	95.02	(0.92)	0.95	(9.40)
32	GAS +B.L. ($/MCF)	6.20	5.57	4.43	4.87	(10.16)	(20.47)	9.93
33	OTHER - C.T.	#N/A	#N/A	106.62	113.01	#N/A	#N/A	5.99
	FUEL COST ($ / MMBtu)							
34	COAL + GAS B.L. + OIL B.L.	4.58	4.51	4.51	4.14	(1.53)	0.00	(8.20)
35	GAS - Generation	6.02	5.41	4.52	4.74	(10.13)	(16.45)	4.87
36	OTHER - C.T.	#N/A	#N/A	18.20	19.34	#N/A	#N/A	6.26
37	TOTAL ($/MMBtu)	4.85	4.70	4.51	4.33	(3.09)	(4.04)	(3.99)
	BTU BURNED (Btu / kWh)							
38	COAL + GAS B.L. + OIL B.L.	10,670	10,854	11,113	11,181	1.72	2.39	0.61
39	GAS - Generation	6,963	7,107	6,842	6,824	2.07	(3.73)	(0.26)
40	OTHER - C.T.	#N/A	#N/A	13,285	14,063	#N/A	#N/A	5.86
41	TOTAL (Btu/kWh)	9,665	9,748	9,089	9,282	0.86	(6.76)	2.12
	FUEL COST (¢ / kWh)							
42	COAL + GAS B.L. + OIL B.L.	4.88	4.89	5.01	4.63	0.20	2.45	(7.58)
43	GAS - Generation	4.19	3.84	3.09	3.23	(8.35)	(19.53)	4.53
44	LANDFILL GAS	2.52	2.59	2.67	2.75	2.78	3.09	3.00
45	OTHER - C.T.	#N/A	#N/A	24.18	27.19	#N/A	#N/A	12.45
46	OTHER GENERATION	5.01	4.85	3.59	4.00	(3.19)	(25.98)	11.42
47	TOTAL (¢ / kWh)	4.70	4.59	4.11	4.02	(2.34)	(10.46)	(2.19)

Schedule CCE-1

Projected Purchased Power Capacity Payments / (Receipts)
Gulf Power Company
For January 2014 - December 2014

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments / (Receipts) ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Capacity Payments / (Receipts) ($)	2,561,806	2,561,807	2,463,385	2,463,385	3,053,926	7,254,089	7,254,089	7,254,089	7,254,089	7,254,089	7,254,089	7,254,089	63,882,932
3	Projected Transmission Revenue	(13,000)	(15,000)	(12,000)	(12,000)	(13,000)	(9,000)	(9,000)	(11,000)	(8,000)	(13,000)	(16,000)	(17,000)	(148,000)
4	Total Projected Capacity Payments / (Receipts) (Line 1 + 2 + 3) ($)	2,548,806	2,546,807	2,451,385	2,451,385	3,040,926	7,245,089	7,245,089	7,243,089	7,246,089	7,241,089	7,238,089	7,237,089	63,734,932
5	Jurisdictional %	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6	Projected Jurisdictional Capacity Payments / (Receipts) (Line 4 x Line 5) ($)	2,474,163	2,472,223	2,379,595	2,379,595	2,951,871	7,032,914	7,032,914	7,030,972	7,033,884	7,029,031	7,026,119	7,025,148	61,868,429
7	True-Up ($)													2,161,010
8	Total Jurisdictional Amount to be Recovered (Line 6 + Line 7) ($)													64,029,439
9	Revenue Tax Multiplier													1.00072
10	Total Recoverable Capacity Payments / (Receipts) (Line 8 x Line 9) ($)													64,075,540

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,788,856.26	97.07146%
FERC	53,967.91	2.92854%
Total	1,842,824.17	100.00000%

* Based on 2012 Actual Data

Schedule CCE-1A

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD JANUARY 2014 - DECEMBER 2014

1.	Estimated over/(under)-recovery, January 2013 - December 2013 (Schedule CCE-1B, Line 15 + Line 18)	($2,263,786)
2.	Final over/(under)-recovery, January 2012 - December 2012 (Exhibit RWD-1, Schedule CCA-1, filed March 1, 2013)	102,776
3.	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2014 - December 2014)	($2,161,010)
4.	Jurisdictional kWh sales, January 2014 - December 2014	11,154,278,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)	0.0194

SCHEDULE CCE-1B

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED TRUE-UP AMOUNT
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2013 - DECEMBER 2013

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	419,141	(105,345)	341,687	42,050	(4,527)	(2,216)	0	0	0	0	0	0	690,790
2	Other Capacity Payments / (Receipts) ($)	1,961,029	2,003,882	2,048,096	2,003,745	2,601,116	6,780,108	7,267,649	7,018,398	7,017,398	2,239,398	2,240,398	2,240,398	45,421,615
3	Transmission Revenue ($)	(9,396)	(10,325)	(11,718)	(9,510)	(10,547)	(9,573)	(10,000)	(13,000)	(10,000)	(15,000)	(18,000)	(19,000)	(146,069)
4	Total Capacity Payments/(Receipts) ($)	2,370,774	1,888,212	2,378,065	2,036,285	2,586,042	6,768,319	7,257,649	7,005,398	7,007,398	2,224,398	2,222,398	2,221,398	45,966,336
5	Jurisdictional %	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	0.9657346	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	2,289,538	1,823,512	2,296,580	1,966,511	2,497,430	6,536,400	7,008,963	6,765,355	6,767,287	2,148,178	2,146,247	2,145,281	44,391,282
7	Retail kWh Sales							1,198,377,000	1,181,726,000	1,034,929,000	865,410,000	762,800,000	852,320,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/kWh)							0.397	0.397	0.397	0.397	0.397	0.397	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	3,092,021	2,777,430	3,146,584	2,854,644	3,482,025	4,346,407	4,757,557	4,691,452	4,108,668	3,435,678	3,028,316	3,383,710	43,104,492
10	Revenue Taxes (Line 9 x .00072) ($)	2,226	2,000	2,266	2,055	2,507	3,129	3,425	3,378	2,958	2,474	2,180	2,436	31,034
11	True-Up Provision ($)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(78,807)	(945,684)
12	Capacity Cost Recovery Revenues Net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	3,010,988	2,696,623	3,066,511	2,773,782	3,400,711	4,264,471	4,675,325	4,609,267	4,026,903	3,354,397	2,947,329	3,302,467	42,127,774
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	721,450	873,111	768,931	807,271	903,281	(2,271,929)	(2,333,638)	(2,156,088)	(2,740,384)	1,206,219	801,082	1,157,186	(2,263,508)
14	Interest Provision ($)	(26)	34	100	147	197	137	15	(93)	(212)	(246)	(192)	(139)	(278)
15	Total Estimated True-Up for the Period January 2013 - December 2013 (Line 13 + Line 14) ($)													(2,263,786)
16	Beginning Balance True-Up & Interest Provision ($)	(842,908)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(822,178)	(2,899,552)	(5,561,341)	(4,276,561)	(3,396,864)	(842,908)
17	True-Up Collected/(Refunded) ($)	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	78,807	945,684
18	Adjustment ($)	0	0	0	0	0		0	0	0	0	0	0	0
19	End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	(42,677)	909,275	1,757,113	2,643,338	3,625,623	1,432,638	(822,178)	(2,899,552)	(5,561,341)	(4,276,561)	(3,396,864)	(2,161,010)	(2,161,010)

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2014 - December 2014

Rate Class	A Average 12 CP Load Factor at Meter	B 2014 Projected KWH Sales at Meter	C Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	D Demand Loss Expansion Factor	E Energy Loss Expansion Factor	F 2014 Projected KWH Sales at Generation Col B x Col E	G Projected Avg 12 CP KW at Generation Col C x Col D	H Percentage of KWH Sales at Generation Col F / Total Col F	I Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP	57.025261%	5,264,442,000	1,053,855.24	1.00820508	1.00777864	5,305,392,199	1,062,502.21	47.58292%	56.58285%
GS	65.082883%	291,284,000	51,091.16	1.00820395	1.00777656	293,549,188	51,510.31	2.63278%	2.74315%
GSD, GSDT, GSTOU	75.900487%	2,733,688,000	411,149.98	1.00800263	1.00762887	2,754,542,950	414,440.26	24.70491%	22.07074%
LP, LPT	85.148219%	1,233,654,000	165,391.69	0.97344897	0.98364378	1,213,476,084	161,000.37	10.88341%	8.57397%
PX, PXT, RTP, SBS	88.430490%	1,477,617,000	190,746.13	0.95247952	0.96644352	1,428,033,375	181,681.78	12.80773%	9.67534%
OS - I / II	782.722832%	109,296,000	1,594.01	1.00802086	1.00777465	110,145,738	1,606.80	0.98787%	0.08557%
OS-III	101.182319%	44,297,000	4,997.65	1.00838359	1.00778595	44,641,894	5,039.55	0.40038%	0.26838%
TOTAL		11,154,278,000	1,878,825.86			11,149,781,428	1,877,781.28	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2012 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2014 - December 2014

Rate Class	A 2014 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F 2014 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RSVP	47.58292%	56.58285%	2,345,309	33,466,861	35,812,170	5,264,442,000	0.680
GS	2.63278%	2.74315%	129,767	1,622,481	1,752,248	291,284,000	0.602
GSD, GSDT, GSTOU	24.70491%	22.07074%	1,217,677	13,054,104	14,271,781	2,733,688,000	0.522
LP, LPT	10.88341%	8.57397%	536,431	5,071,216	5,607,647	1,233,654,000	0.455
PX, PXT, RTP, SBS	12.80773%	9.67534%	631,279	5,722,640	6,353,919	1,477,617,000	0.430
OS - I / II	0.98787%	0.08557%	48,691	50,612	99,303	109,296,000	0.091
OS-III	0.40038%	0.26838%	19,734	158,738	178,472	44,297,000	0.403
TOTAL	100.00000%	100.00000%	$4,928,888	$59,146,652	$64,075,540	11,154,278,000	0.574

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 10) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 10) x 12 / 13 x Col B

Gulf Power Company
2014 Capacity Contracts

Schedule CCE-4
Page 1 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other			
South Carolina PSA	9/1/2003	-	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs
2013

Contract	January MW	January $	February MW	February $	March MW	March $	April MW	April $	May MW	May $	June MW	June $
Southern Intercompany Interchange	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0
PPAs												
Coral Power,LLC											0.0	0
Southern Power Company											0.0	0
Shell Energy N.A. (U.S.), LP												
Other												
South Carolina PSA												
Total		2,561,806		2,561,807		2,463,385		2,463,385		3,053,926		7,254,089

Docket No. 130001-EI
2014 Projection Filing
Exhibit RWD-3, Page 41 of 42

Gulf Power Company
2014 Capacity Contracts

Schedule CCE-4
Page 2 of 2

Contract/Counterparty	Term Start	Term End [1]	Contract Type
Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
PPAs			
Coral Power,LLC	6/1/2009	5/31/2014	Firm
Southern Power Company	6/1/2009	5/31/2014	Firm
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023	Non-Firm
Other			
South Carolina PSA	9/1/2003	-	Other

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Contract megawatts become firm no later than June 1, 2014.

Capacity Costs

2013	July		August		September		October		November		December		
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	Total $
Southern Intercompany Interchange	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0
PPAs													
Coral Power,LLC	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	
Southern Power Company	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	
Shell Energy N.A. (U.S.), LP													
Total PPAs													63,920,684
Other													
South Carolina PSA													(37,752)
Total		7,254,089		7,254,089		7,254,089		7,254,089		7,254,089		7,254,089	63,882,932

EXHIBIT TO THE TESTIMONY OF

M. A. YOUNG, III

IN FPSC DOCKET 130001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 44
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION M.A. Young - MAY-1

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2012 - DECEMBER 2012 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2012 - December 2012 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
February filing	Crist 6	POH - RSH		72.0	291.0	No change in EAF Unit was on RSH and did not start the PO until 2/4/2012
December filing	Crist 7	MOH - POH		50.2	465.0	No change in EAF 50.2 MOH changed to POH

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2012 - December 2012

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 6	1	02/18/12 - 04/29/12	1727.0	02/04/12 - 04/26/12	1930.2
Crist 7	2	10/06/12 - 12/23/12	1897.0	09/15/12 - 12/20/12	2305.8
Smith 2	3	01/21/12 - 02/12/12	552.0		0.0
Daniel 1	4	01/07/12 - 02/12/12	888.0	03/18/12 - 05/11/12	1210.1

* Planned outage hours in the January 2012 - December 2012 period only.

Notes: 1. The outage date was changed subsequent to the target filing.

2. The outage date was changed subsequent to the target filing.

3. The outage was canceled subsequent to the target filing.

4. The outage date was changed subsequent to the target filing.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Crist 4

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	1.8	0.0	2.3	0.0	0.0	3.1	
	0.0	0.0	3.0	0.0	0.0	0.0	10.1
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	2.0	0.0	0.0	2.0
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	367.1	696.0	662.5	580.3	744.0	583.3	
	744.0	744.0	716.7	742.0	165.9	0.0	6745.8

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(10.1 + 0.0 + 2.0 + 0.0)}{(8784.0 - 0.0 - 6745.8)}$$

$$EUOR = 0.0059$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.0059\ (8784.0 - 0.0 - 0.0))}{8784.0} \right] \times 100 = 99.4\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Crist 5

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	1.2	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1.2
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MOH	0.0	0.0	42.0	15.2	0.0	0.0	
	0.0	3.5	0.0	0.0	26.0	0.0	86.7
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	303.7	0.0	23.2	121.3	0.0	0.0	
	98.1	113.3	0.0	0.0	360.6	744.0	1764.2

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(1.2 + 0.0 + 86.7 + 0.0)}{(8784.0 - 0.0 - 1764.2)}$$

$$EUOR = 0.0125$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.0125\ (8784.0 - 0.0 - 0.0))}{8784.0} \right] \times 100 = 98.8\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	26.5	0.0	30.4	0.0	56.9
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.1	0.0	0.0	0.0	16.8	0.0	16.9
MOH	0.0	0.0	0.0	0.0	0.0	84.0	
	0.0	23.1	9.5	69.9	134.1	32.0	352.4
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	6.5	0.0	0.0	0.0	6.5
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	624.0	743.0	563.2	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1930.2
RSH	624.1	72.0	0.0	0.0	0.0	98.9	
	470.9	335.5	0.0	0.0	0.0	209.8	1811.1

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(56.9 + 16.9 + 352.4 + 6.5)}{(8784.0 - 1930.2 - 1811.1)}$$

$$EUOR = 0.0858$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1727.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1727.0 + 0.0858\ (8784.0 - 1727.0 - 0.0))}{8784.0} \right] \times 100 = 73.4\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	10.0	0.0	0.0	6.9	0.0	0.0	
	0.0	2.9	0.0	0.0	0.0	0.0	19.7
EFOH	0.0	0.0	0.0	22.0	0.4	0.0	
	18.4	0.0	0.0	0.0	0.0	0.0	40.8
MOH	49.7	0.0	0.0	0.0	0.0	53.2	
	45.8	0.0	0.0	0.0	0.0	0.0	148.6
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.7	0.0	0.0	0.0	0.0	0.0	0.7
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	384.0	744.0	721.0	456.8	2305.8
RSH	48.4	0.0	0.0	35.9	261.2	0.0	
	0.0	43.7	336.0	0.0	0.0	0.0	725.3

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(19.7 + 40.8 + 148.6 + 0.7)}{(8784.0 - 2305.8 - 725.3)}$$

$$EUOR = 0.0365$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1897.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1897.0 + 0.0365\ (8784.0 - 1897.0 - 0.0))}{8784.0} \right] \times 100 = 75.5\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	5.6	0.0	0.0	0.0	
	33.4	3.1	0.0	0.0	32.9	0.0	75.0
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	2.7	1.4	0.0	0.0	0.0	4.1
MOH	0.0	0.0	0.0	159.0	22.9	0.0	
	0.0	0.0	281.0	0.0	0.0	0.0	462.8
EMOH	0.0	0.0	0.0	4.8	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	4.8
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0	289.9	0.0	
	0.0	0.0	147.6	744.0	256.3	0.0	1437.9

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(75.0 + 4.1 + 462.8 + 4.8)}{(8784.0 - 0.0 - 1437.9)}$$

$$EUOR = 0.0744$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.0744\ (8784.0 - 0.0 - 0.0))}{8784.0} \right] \times 100 = 92.6\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	1.2	0.4	0.0	0.0	0.0	0.0	1.6
MOH	0.0	96.6	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	245.0	341.6
EMOH	0.0	0.0	0.0	0.0	0.9	0.0	
	0.6	40.7	0.0	0.0	0.0	0.0	42.2
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	744.0	599.4	743.0	229.9	90.9	720.0	
	52.1	0.0	0.0	0.0	252.1	499.0	3930.5

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(0.0 + 1.6 + 341.6 + 42.2)}{(8784.0 - 0.0 - 3930.5)}$$

$$EUOR = 0.0794$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 552.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(552.0 + 0.0794\ (8784.0 - 552.0 - 0.0))}{8784.0} \right] \times 100 = 86.3\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EFOH	0.0	0.0	0.7	0.0	0.0	0.0	
	0.4	10.3	0.0	4.7	11.3	0.0	27.4
MOH	179.2	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	120.0	184.0	483.2
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	330.0	720.0	160.1	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1210.1
RSH	449.8	696.0	314.1	0.0	317.5	337.7	
	0.0	115.7	720.0	670.3	150.3	560.0	4331.4

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(0.0 + 27.4 + 483.2 + 0.0)}{(8784.0 - 1210.1 - 4331.4)}$$

$$EUOR = 0.1575$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 888.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(888.0 + 0.1575\ (8784.0 - 888.0 - 0.0))}{8784.0} \right] \times 100 = 75.7\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2012 - December 2012
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	4.0	1.2	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	5.2
EFOH	2.3	0.0	1.2	0.0	0.0	1.1	
	0.0	13.3	0.0	0.0	0.0	0.0	17.9
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	2.9	89.8	66.0	121.0	76.0	355.6
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	696.0	743.0	720.0	744.0	720.0	
	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	421.2	696.0	197.1	0.0	314.0	482.4	
	340.9	146.6	630.3	678.0	600.0	668.0	5174.4

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(5.2 + 17.9 + 355.6 + 0.0)}{(8784.0 - 0.0 - 5174.4)}$$

$$EUOR = 0.1049$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.1049\ (8784.0 - 0.0 - 0.0))}{8784.0} \right] \times 100 = 89.5\ \%$$

Note: Please refer to page 12 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2012 - December 2012

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 4	97.7	99.4	98.4	10.00
Crist 5	97.9	98.8	98.6	10.00
Crist 6	74.8	73.4	72.2	-5.38
Crist 7	72.6	75.5	74.3	10.00
Smith 1	93.6	92.6	90.7	-3.45
Smith 2	87.7	86.3	85.0	-5.19
Daniel 1	84.1	75.7	81.5	-10.00
Daniel 2	93.4	89.5	90.5	-10.00

* As appropriate from page 5, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Refer to pages 3 through 10 of this Schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Crist 4

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	14434.1	0.0	3180.0	6190.0	0.0	6202.0	
	0.0	0.0	0.0	0.0	20649.1	29803.2	80458.4
BTU/Lb*	11863.1	0.0	11596.9	11533.4	0.0	11769.4	
	0.0	0.0	0.0	0.0	11897.5	11845.8	11822.4
Coal, MMBTU	171233.2	0.0	36878.1	71391.7	0.0	72993.8	
	0.0	0.0	0.0	0.0	245672.7	353042.7	951212.2
Oil, MMBTU	357.5	0.0	180.6	48.3	0.0	719.4	
	0.0	0.0	0.0	0.0	826.9	18.0	2150.7
Gas, MMBTU	30660.0	0.0	735.0	0.0	0.0	379.0	
	0.0	0.0	0.0	0.0	82883.0	95241.0	209898.0
Startup, MMBTU **	-400.0	0.0	-400.0	0.0	0.0	-400.0	
	0.0	0.0	0.0	0.0	-400.0	0.0	-1600.0
Total Fuel Consumption, MMBTU	201850.7	0.0	37393.7	71440.0	0.0	73692.2	
	0.0	0.0	0.0	0.0	328982.6	448301.7	1161660.9
Net MWH Generation***	15827	0	3109	5896	0	6507	
	0	0	0	0	27967	40050	99356
Average Net Operating Heat Rate	12754	---	12028	12117	---	11325	
	---	---	---	---	11763	11194	11692

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Crist 5

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	12735.2	25776.9	33282.6	25794.0	23887.2	29232.2	
	24637.7	29820.6	29036.9	29838.8	11298.4	0.0	275340.5
BTU/Lb*	10704.0	11553.2	11561.9	11631.6	11848.9	11767.0	
	11605.7	11594.8	11466.4	11664.4	11846.2	0.0	11594.8
Coal, MMBTU	136317.6	297805.7	384810.1	300025.5	283037.0	343975.3	
	285937.8	345763.9	332948.7	348051.7	133843.1	0.0	3192516.4
Oil, MMBTU	259.8	1240.4	79.2	294.0	430.4	539.2	
	420.5	1293.9	1246.8	361.0	196.7	0.0	6361.9
Gas, MMBTU	61228.0	26815.0	0.0	23521.0	92728.0	42729.0	
	72093.0	2292.0	376.0	29.0	16691.0	0.0	338502.0
Startup, MMBTU **	-400.0	0.0	0.0	-400.0	0.0	0.0	
	0.0	-400.0	0.0	0.0	0.0	0.0	-1200.0
Total Fuel Consumption, MMBTU	197405.4	325861.1	384889.3	323440.5	376195.4	387243.5	
	358451.3	348949.8	334571.5	348441.7	150730.8	0.0	3536180.3
Net MWH Generation***	18201	29099	32188	27682	35005	32165	
	30902	31374	31827	29382	13182	0	311007
Average Net Operating Heat Rate	10846	11198	11958	11684	10747	12039	
	11600	11122	10512	11859	11435	---	11370

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	17727.5	0.0	0.0	21666.0	134903.7	109639.1	
	50228.0	78907.5	125347.3	122131.9	87529.0	87476.5	835556.5
BTU/Lb*	11471.7	0.0	0.0	11740.0	11918.2	11281.0	
	11734.1	11575.6	11555.3	11687.2	11949.9	11935.1	11694.0
Coal, MMBTU	203364.6	0.0	0.0	254358.8	1607809.3	1236838.7	
	589380.4	913401.7	1448425.7	1427379.9	1045962.8	1044040.8	9770962.7
Oil, MMBTU	0.0	0.0	0.0	0.0	1.5	0.0	
	0.0	0.0	183.3	102.5	85.8	355.1	728.2
Gas, MMBTU	2201.0	0.0	0.0	26304.0	0.0	2040.0	
	16252.0	7691.0	2466.0	3900.0	31887.0	21972.0	114713.0
Startup, MMBTU **	0.0	0.0	0.0	-4040.0	0.0	0.0	
	-4040.0	-4040.0	-4040.0	-4040.0	-8080.0	0.0	-28280.0
Total Fuel Consumption, MMBTU	205565.6	0.0	0.0	276622.8	1607810.8	1238878.7	
	601592.4	917052.7	1447035.0	1427342.4	1069855.6	1066367.9	9858123.9
Net MWH Generation***	17291	0	0	22677	156777	119706	
	57513	79215	134551	132182	98860	101790	920562
Average Net Operating Heat Rate	11889	---	---	12198	10255	10349	
	10460	11577	10755	10798	10822	10476	10709

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	144772.1	130445.5	134835.7	130316.0	106553.5	141428.4	
	143676.9	141886.0	0.0	0.0	0.0	72713.5	1146627.6
BTU/Lb*	11804.0	11660.4	11640.7	11684.7	11864.3	11771.9	
	11613.9	11651.3	0.0	0.0	0.0	11728.0	11709.0
Coal, MMBTU	1708889.9	1521046.7	1569581.9	1522703.4	1264182.7	1664881.0	
	1668649.1	1653156.4	0.0	0.0	0.0	852783.9	13425875.0
Oil, MMBTU	333.5	423.6	215.6	0.0	202.0	400.5	
	55.0	607.9	0.0	0.0	0.0	657.0	2895.1
Gas, MMBTU	161271.0	514712.0	609045.0	513475.0	358304.0	387433.0	
	506284.0	391121.0	0.0	0.0	0.0	24109.0	3465754.0
Startup, MMBTU **	-4512.0	0.0	0.0	-2256.0	-2256.0	-2256.0	
	-2256.0	0.0	0.0	0.0	0.0	-4512.0	-18048.0
Total Fuel Consumption, MMBTU	1865982.4	2036182.3	2178842.5	2033922.4	1620432.7	2050458.5	
	2172732.1	2044885.3	0.0	0.0	0.0	873037.9	16876476.1
Net MWH Generation***	163186	178586	191799	174070	134669	186127	
	190868	188298	0	0	0	74439	1482042
Average Net Operating Heat Rate	11435	11402	11360	11685	12033	11016	
	11383	10860	---	---	---	11728	11387

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Smith 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	51780.0	49000.0	49404.0	40098.0	30026.0	48244.2	
	54128.0	49340.0	20348.0	0.0	27812.0	49292.0	469472.2
BTU/Lb*	11266.2	11151.6	11242.4	11203.9	11534.3	11617.8	
	11549.3	11683.0	11643.2	0.0	12108.3	12451.7	11566.8
Coal, MMBTU	583363.8	546428.4	555419.5	449254.0	346328.9	560491.5	
	625140.5	576439.2	236915.8	0.0	336756.0	613769.2	5430306.8
Oil, MMBTU	381.9	718.8	957.8	2449.6	1541.0	861.1	
	1407.7	3394.5	2129.4	0.0	2768.4	91.2	16701.4
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-964.0	-964.0	0.0	
	0.0	-964.0	0.0	0.0	-1928.0	0.0	-4820.0
Total Fuel Consumption, MMBTU	583745.7	547147.2	556377.3	450739.6	346905.9	561352.6	
	626548.2	578869.7	239045.2	0.0	337596.4	613860.4	5442188.2
Net MWH Generation***	54180	50839	51780	42123	32679	52221	
	57991	52471	21638	0	31273	56702	503897
Average Net Operating Heat Rate	10774	10762	10745	10701	10616	10750	
	10804	11032	11047	---	10795	10826	10800

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Smith 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	0.0	0.0	0.0	36306.0	47534.0	0.0	
	53708.0	50648.0	50802.0	50364.0	31572.0	0.0	320934.0
BTU/Lb*	0.0	0.0	0.0	11263.8	11522.6	0.0	
	11521.7	11670.2	11611.9	11754.0	11941.2	0.0	11608.1
Coal, MMBTU	0.0	0.0	0.0	408943.5	547715.3	0.0	
	618807.5	591072.3	589907.7	591978.5	377007.6	0.0	3725432.4
Oil, MMBTU	0.0	0.0	0.0	1420.2	584.2	0.0	
	2340.6	2775.6	2709.8	750.3	146.5	0.0	10727.2
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-1190.0	0.0	0.0	
	-1190.0	0.0	0.0	0.0	0.0	0.0	-2380.0
Total Fuel Consumption, MMBTU	0.0	0.0	0.0	409173.7	548299.5	0.0	
	619958.1	593847.9	592617.5	592728.8	377154.1	0.0	3733779.6
Net MWH Generation***	0	0	0	38968	51135	0	
	55409	51886	51705	52751	34407	0	336261
Average Net Operating Heat Rate	---	---	---	10500	10723	---	
	11189	11445	11462	11236	10962	---	11104

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	37258.0	0.0	30976.0	0.0	78478.0	105718.0	
	266234.0	154180.0	0.0	31290.0	189396.0	0.0	893530.0
BTU/Lb*	11070.4	0.0	10083.7	0.0	10898.7	11208.5	
	10028.7	9199.0	0.0	8997.8	8982.0	0.0	9888.9
Coal, MMBTU	412461.0	0.0	312352.7	0.0	855308.2	1184940.2	
	2669980.9	1418301.8	0.0	281541.2	1701154.9	0.0	8836040.9
Oil, MMBTU	10235.0	0.0	4609.7	0.0	20622.3	2547.7	
	1427.3	12356.7	0.0	4198.8	1871.3	0.0	57868.8
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-4777.4	0.0	-2388.7	0.0	-4777.4	-2388.7	
	0.0	-2388.7	0.0	-2388.7	0.0	0.0	-19109.6
Total Fuel Consumption, MMBTU	417918.6	0.0	314573.7	0.0	871153.1	1185099.2	
	2671408.2	1428269.8	0.0	283351.3	1703026.2	0.0	8874800.1
Net MWH Generation***	41008	0	31988	0	79357	117594	
	260016	127713	0	24315	168166	0	850157
Average Net Operating Heat Rate	10191	---	9834	---	10978	10078	
	10274	11183	---	11653	10127	---	10439

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2012 - December 2012

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	110582.0	0.0	202954.0	253522.0	105646.0	43078.0	
	100082.0	146898.0	0.0	0.0	0.0	0.0	962762.0
BTU/Lb*	9760.4	0.0	10337.4	10847.9	10590.7	11316.6	
	10187.1	9084.1	0.0	0.0	0.0	0.0	10270.3
Coal, MMBTU	1079324.6	0.0	2098016.7	2750181.3	1118865.1	487496.5	
	1019545.3	1334436.1	0.0	0.0	0.0	0.0	9887865.6
Oil, MMBTU	140.5	0.0	3445.9	489.1	2699.0	3189.9	
	2639.7	12420.8	0.0	0.0	0.0	0.0	25024.9
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	-2388.7	0.0	-2388.7	-2388.7	
	-2388.7	-2388.7	0.0	0.0	0.0	0.0	-11943.5
Total Fuel Consumption, MMBTU	1079465.1	0.0	2099073.9	2750670.4	1119175.4	488297.7	
	1019796.3	1344468.2	0.0	0.0	0.0	0.0	9900947.0
Net MWH Generation***	109302	0	203848	275492	102740	46683	
	92898	119819	0	0	0	0	950782
Average Net Operating Heat Rate	9876	---	10297	9985	10893	10460	
	10978	11221	---	---	---	---	10413

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Crist 4

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11741	11827	11827	11502	11336	11205	
		11615	11149	11260	11432	11314	11767	
2.	Target Heat Rate	12151	11827	12362	12151	11336	11683	
	at Actual Conditions**	11615	11149	11260	11432	11198	11396	
3.	Adjustment to Actual	-410	0	-535	-649	0	-478	
	Heat Rate (1-2)	0	0	0	0	116	371	
4.	Actual Heat Rate	12754	0	12028	12117	0	11325	
	(Page 2 of Sched. 3)	0	0	0	0	11763	11194	
5.	Adjusted Actual	12344	0	11493	11468	0	10847	
	Heat Rate (4+3)	0	0	0	0	11879	11565	
6.	Net MWH Generation	15827	0	3109	5896	0	6507	
		0	0	0	0	27967	40050	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							11722

* From pages 20 & 21, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Crist 5

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11694	11744	11806	11195	11306	11119	
		11344	11392	11575	11364	11638	11686	
2.	Target Heat Rate	12046	11983	11626	11308	11608	11750	
	at Actual Conditions**	11813	11806	12342	12233	12252	11686	
3.	Adjustment to Actual	-352	-239	180	-113	-302	-631	
	Heat Rate (1-2)	-469	-414	-767	-869	-614	0	
4.	Actual Heat Rate	10846	11198	11958	11684	10747	12039	
	(Page 3 of Sched. 3)	11600	11122	10512	11859	11435	0	
5.	Adjusted Actual	10494	10959	12138	11571	10445	11408	
	Heat Rate (4+3)	11131	10708	9745	10990	10821	0	
6.	Net MWH Generation	18201	29099	32188	27682	35005	32165	
		30902	31374	31827	29382	13182	0	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							10961

* From pages 22 & 23, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11648	11747	0	11554	11324	11134	
		11060	11321	11491	12230	11308	11732	
2.	Target Heat Rate	11620	11747	0	12030	10961	10816	
	at Actual Conditions**	10834	11168	11156	11526	10789	10856	
3.	Adjustment to Actual	28	0	0	-476	363	318	
	Heat Rate (1-2)	226	153	335	704	519	876	
4.	Actual Heat Rate	11889	0	0	12198	10255	10349	
	(Page 4 of Sched. 3)	10460	11577	10755	10798	10822	10476	
5.	Adjusted Actual	11917	0	0	11722	10618	10667	
	Heat Rate (4+3)	10686	11730	11090	11502	11341	11352	
6.	Net MWH Generation	17291	0	0	22677	156777	119706	
		57513	79215	134551	132182	98860	101790	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							11131

* From pages 24 & 25, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10415	10482	10727	10980	10658	10652	
		10655	10653	10835	10421	0	10844	
2.	Target Heat Rate	10903	10907	11281	11816	11156	11139	
	at Actual Conditions**	11187	11209	10835	10421	0	11461	
3.	Adjustment to Actual	-488	-425	-554	-836	-498	-487	
	Heat Rate (1-2)	-532	-556	0	0	0	-617	
4.	Actual Heat Rate	11435	11402	11360	11685	12033	11016	
	(Page 5 of Sched. 3)	11383	10860	0	0	0	11728	
5.	Adjusted Actual	10947	10977	10806	10849	11535	10529	
	Heat Rate (4+3)	10851	10304	0	0	0	11111	
6.	Net MWH Generation	163186	178586	191799	174070	134669	186127	
		190868	188298	0	0	0	74439	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 $=(\Sigma(5*6)/\Sigma 6)$							10836

* From pages 26 & 27, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Smith 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10580	10580	10581	10583	10784	10696	
		10663	10572	10756	10603	10597	10580	
2.	Target Heat Rate	11226	11221	11291	11172	11156	11233	
	at Actual Conditions**	11162	11276	11190	10603	11236	11147	
3.	Adjustment to Actual	-646	-641	-710	-589	-372	-537	
	Heat Rate (1-2)	-499	-704	-434	0	-639	-567	
4.	Actual Heat Rate	10774	10762	10745	10701	10616	10750	
	(Page 6 of Sched. 3)	10804	11032	11047	0	10795	10826	
5.	Adjusted Actual	10128	10121	10035	10112	10244	10213	
	Heat Rate (4+3)	10305	10328	10613	0	10156	10259	
6.	Net MWH Generation	54180	50839	51780	42123	32679	52221	
		57991	52471	21638	0	31273	56702	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							10211

* From pages 28 & 29 , Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Smith 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10836	10593	10606	10608	10448	10549	
		10466	10464	10626	10351	10456	10583	
2.	Target Heat Rate	10836	10593	10606	11292	10998	10549	
	at Actual Conditions**	11266	11553	11478	11137	11203	10583	
3.	Adjustment to Actual	0	0	0	-684	-550	0	
	Heat Rate (1-2)	-800	-1089	-852	-786	-747	0	
4.	Actual Heat Rate	0	0	0	10500	10723	0	
	(Page 7 of Sched. 3)	11189	11445	11462	11236	10962	0	
5.	Adjusted Actual	0	0	0	9816	10173	0	
	Heat Rate (4+3)	10389	10356	10610	10450	10215	0	
6.	Net MWH Generation	0	0	0	38968	51135	0	
		55409	51886	51705	52751	34407	0	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							10310

* From pages 30 & 31, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	11272	11146	10872	10648	10555	10492	
		10614	10418	10602	10753	11037	10968	
2.	Target Heat Rate	10536	11146	10502	10648	10641	10585	
	at Actual Conditions**	10551	11456	10602	10471	10288	10968	
3.	Adjustment to Actual	736	0	370	0	-86	-93	
	Heat Rate (1-2)	63	-1038	0	282	749	0	
4.	Actual Heat Rate***	10191	0	9834	0	10978	10078	
	(Page 8 of Sched. 3)	10274	11183	0	11653	10127	0	
5.	Adjusted Actual	10927	0	10204	0	10892	9985	
	Heat Rate (4+3)	10337	10145	0	11935	10876	0	
6.	Net MWH Generation	41008	0	31988	0	79357	117594	
		260016	127713	0	24315	168166	0	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							10487

* From pages 32 & 33, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2012 - December 2012
Adjusted to Target Basis Using Heat Rate
Equations Filed September 01, 2011

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10416	11000	10912	10714	10614	10560	
		10334	10478	10422	10486	10983	10953	
2.	Target Heat Rate	10115	11000	10312	10287	10933	11223	
	at Actual Conditions**	10808	11206	10422	10486	10983	10953	
3.	Adjustment to Actual	301	0	600	427	-319	-663	
	Heat Rate (1-2)	-474	-728	0	0	0	0	
4.	Actual Heat Rate***	9876	0	10297	9985	10893	10460	
	(Page 9 of Sched. 3)	10978	11221	0	0	0	0	
5.	Adjusted Actual	10177	0	10897	10412	10574	9797	
	Heat Rate (4+3)	10504	10493	0	0	0	0	
6.	Net MWH Generation	109302	0	203848	275492	102740	46683	
		92898	119819	0	0	0	0	
7.	Adjusted Actual Heat Rate for January 2012 - December 2012 =(Σ (5*6) / Σ 6)							10495

* From pages 34 & 35, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Actual Values of
Target Heat Rate Equation Parameters
for January 2012 - December 2012

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 4							
	+3						
	AKW * 10	42.2	0.0	39.8	42.2	0.0	48.7
		0.0	0.0	0.0	0.0	50.4	53.8
	+6						
	LSRF * 10	1828.5	0.0	1616.2	1876.1	0.0	2550.9
		0.0	0.0	0.0	0.0	2593.7	2898.9
Crist 5							
	+3						
	AKW * 10	41.3	41.8	47.5	47.4	47.1	44.7
		47.8	50.0	44.2	39.5	39.4	0.0
	+6						
	LSRF * 10	1743.0	1784.4	2436.7	2431.1	2363.5	2090.4
		2350.3	2652.5	2049.5	1564.8	1559.7	0.0
Crist 6							
	+3						
	AKW * 10	144.2	0.0	0.0	144.7	210.7	222.9
		210.6	205.5	196.7	196.1	177.6	202.7
	+6						
	LSRF * 10	22044.4	0.0	0.0	26097.6	47063.1	50692.7
		45293.6	43943.4	39019.7	39073.4	33282.3	41952.2
Crist 7							
	+3						
	AKW * 10	256.6	256.6	258.1	257.0	278.9	279.1
		273.4	270.0	0.0	0.0	0.0	259.2
	+6						
	LSRF * 10	67235.2	66701.1	67859.3	68430.1	82661.0	82312.1
		78740.8	76374.9	0.0	0.0	0.0	73863.3
Smith 1							
	+3						
	AKW * 10	72.8	73.0	70.2	75.1	75.8	72.5
		81.6	70.8	74.3	0.0	72.4	76.2
	+6						
	LSRF * 10	5392.0	5461.8	4963.0	6086.3	6115.0	5405.9
		7279.4	5082.4	5815.5	0.0	5328.1	5918.4
Smith 2							
	+3						
	AKW * 10	0.0	0.0	0.0	79.5	78.3	0.0
		80.1	69.7	71.8	70.9	73.4	0.0
	+6						
	LSRF * 10	0.0	0.0	0.0	7192.0	6886.6	0.0
		7269.7	4897.9	5326.0	5136.1	5594.3	0.0

Actual Values of
Target Heat Rate Equation Parameters
for January 2012 - December 2012

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Daniel 1							
	+3						
	AKW * 10	356.6	0.0	323.5	0.0	297.8	307.6
		349.5	203.3	0.0	329.8	373.1	0.0
	+6						
	LSRF * 10	137447.2	0.0	126738.2	0.0	109840.8	116775.8
		139999.2	45175.0	0.0	125478.0	150302.2	0.0
Daniel 2							
	+3						
	AKW * 10	338.6	0.0	376.2	383.2	238.9	196.5
		230.4	201.5	0.0	0.0	0.0	0.0
	+6						
	LSRF * 10	134328.6	0.0	161048.8	166341.2	66780.0	41528.4
		59455.7	43326.4	0.0	0.0	0.0	0.0

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * [147.87 + 27.22 * JUL - 19.30 * NOV]

+ 8,647

Crist 5 ANOHR = 10^6 / AKW * [332.39 - 15.75 * APR + 18.08 * JUL + 20.39 * AUG + 23.68 * SEP]

+ 1,068 + 0.06941 * LSRF / AKW

Crist 6 ANOHR = 10^6 / AKW * [803.77 + 53.22 * AUG + 61.67 * SEP + 128.86 * OCT - 57.18 * NOV]

+ 3,660 + 0.01561 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [1509.41 - 103.64 * JAN - 97.39 * FEB + 123.28 * APR + 64.40 * SEP - 94.54 * OCT - 86.63 * NOV]

+ 2,982 + 0.00932 * LSRF / AKW

Smith 1 ANOHR = 10^6 / AKW * [128.19 + 10.27 * JUL]

+ 9,465

Smith 2 ANOHR = 10^6 / AKW * [320.27 + 28.73 * JAN - 24.84 * MAY - 26.36 * OCT - 15.30 * NOV]

+ 5,898 + 0.01509 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [521.83 + 65.51 * JAN + 59.16 * JUL]

+ 8,889

Daniel 2 ANOHR = 10^6 / AKW * [24.52 - 110.71 * JAN - 49.24 * JUL - 56.45 * SEP - 73.43 * OCT]

+ 11,929 - 0.00393 * LSRF / AKW

Where:

ANOHR	Average Net Operating Heat Rate, BTU/KWH
AKW	Average Kilowatt Load, KW
LSRF	Load Square Range Factor, KW^2
JAN	January, 0 if not January, 1 if January
FEB	February, 0 if not February, 1 if February
MAR	March, 0 if not March, 1 if March
APR	April, 0 if not April, 1 if April
MAY	May, 0 if not May, 1 if May
JUN	June, 0 if not June, 1 if June
JUL	July, 0 if not July, 1 if July
AUG	August, 0 if not August, 1 if August
SEP	September, 0 if not September, 1 if September
OCT	October, 0 if not October, 1 if October
NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for January 2012 - December 2012

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 4	11479	11722	11135	-6.25
Crist 5	11471	10961	11127	10.00
Crist 6	11457	11131	11113	9.33
Crist 7	10683	10836	10363	-3.18
Smith 1	10628	10211	10309	10.00
Smith 2	10533	10310	10217	6.14
Daniel 1	10703	10487	10382	5.73
Daniel 2	10630	10495	10311	2.46

* From page 5, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

** Refer to pages 10 through 17 of this Schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

If [(2) - (3) - 75] > 0 then points = $\frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$

If [(2) - (3) + 75] < 0 then points = $\frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2012 - December 2012

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 4	10.00	0.000	-6.25	0.047
Crist 5	10.00	0.001	10.00	0.045
Crist 6	-5.38	0.012	9.33	0.115
Crist 7	10.00	0.042	-3.18	0.230
Smith 1	-3.45	0.004	10.00	0.126
Smith 2	-5.19	0.005	6.14	0.115
Daniel 1	-10.00	0.010	5.73	0.117
Daniel 2	-10.00	0.006	2.46	0.123

Company GPIF Points = + 10.00 * 0.000 - 6.25 * 0.047
+ 10.00 * 0.001 + 10.00 * 0.045
- 5.38 * 0.012 + 9.33 * 0.115
+ 10.00 * 0.042 - 3.18 * 0.230
- 3.45 * 0.004 + 10.00 * 0.126
- 5.19 * 0.005 + 6.14 * 0.115
- 10.00 * 0.010 + 5.73 * 0.117
- 10.00 * 0.006 + 2.46 * 0.123

= 3.62

Company reward/penalty = 3.62 points * $459210 per point

= $1,662,342

* From page 5, Schedule 3 of Exhibit to M. A. Young, III's September 01, 2011 GPIF Testimony in Docket 120001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2012 - DECEMBER 2012 PERIOD

CONTENTS

	SCHEDULE 5 PAGE
GPIF Reward/Penalty Table (Actual)	3
GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)	4
Calculation of System Actual GPIF Points	5
Generating Performance Incentive Points Table	6 - 13
GPIF Unit Performance Summary	14
Actual Unit Performance Data	15
Historic Unit Performance Data	16 - 31
Planned Outage Schedules (Actual)	32

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2012 - December 2012

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	13538	4592
+ 9	12184	4133
+ 8	10830	3674
+ 7	9477	3214
+ 6	8123	2755
+ 5	6769	2296
+ 4	5415	1837
+ 3	4061	1378
+ 2	2708	918
+ 1	1354	459
0	0	0
- 1	-1396	-459
- 2	-2793	-918
- 3	-4189	-1378
- 4	-5585	-1837
- 5	-6982	-2296
- 6	-8378	-2755
- 7	-9774	-3214
- 8	-11170	-3674
- 9	-12567	-4133
- 10	-13963	-4592
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2012 - December 2012

Line 1	Beginning of Period Balance of Common Equity	$1,124,948,044
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '12	$1,143,539,003
Line 3	Month of Feb '12	$1,148,748,965
Line 4	Month of Mar '12	$1,158,608,436
Line 5	Month of Apr '12	$1,134,841,584
Line 6	Month of May '12	$1,149,180,761
Line 7	Month of Jun '12	$1,165,987,396
Line 8	Month of Jul '12	$1,154,894,183
Line 9	Month of Aug '12	$1,170,226,356
Line 10	Month of Sep '12	$1,186,075,876
Line 11	Month of Oct '12	$1,165,311,135
Line 12	Month of Nov '12	$1,174,739,926
Line 13	Month of Dec '12	$1,180,741,781
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,158,295,650
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.1928%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$4,732,157
Line 18	Jurisdictional Sales (KWH)	10,662,633,576
Line 19	Total Territorial Sales (KWH)	10,987,827,755
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.0404%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$4,592,104

Issued by: S. W. Connally, Jr.

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2012 - December 2012

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 4	EAF1	0.0%	10.00	0.004
Crist 4	ANOHR1	4.7%	-6.25	-0.295
Crist 5	EAF2	0.1%	10.00	0.010
Crist 5	ANOHR2	4.5%	10.00	0.453
Crist 6	EAF3	1.2%	-5.38	-0.063
Crist 6	ANOHR3	11.5%	9.33	1.076
Crist 7	EAF4	4.2%	10.00	0.423
Crist 7	ANOHR4	23.0%	-3.18	-0.733
Smith 1	EAF5	0.4%	-3.45	-0.013
Smith 1	ANOHR5	12.6%	10.00	1.265
Smith 2	EAF6	0.5%	-5.19	-0.028
Smith 2	ANOHR6	11.5%	6.14	0.706
Daniel 1	EAF7	1.0%	-10.00	-0.097
Daniel 1	ANOHR7	11.7%	5.73	0.670
Daniel 2	EAF8	0.6%	-10.00	-0.060
Daniel 2	ANOHR8	12.3%	2.46	0.303
Gulf Power GPIF Total		100.0%		3.62

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	6	98.40	+ 10	639	11,135
+ 9	5	98.33	+ 9	575	11,162
+ 8	5	98.26	+ 8	511	11,189
+ 7	4	98.19	+ 7	447	11,216
+ 6	4	98.12	+ 6	383	11,243
+ 5	3	98.05	+ 5	320	11,270
+ 4	2	97.98	+ 4	256	11,296
+ 3	2	97.91	+ 3	192	11,323
+ 2	1	97.84	+ 2	128	11,350
+ 1	1	97.77	+ 1	64	11,377
				0	11,404
0	0	97.70	0	0	11,479
				0	11,554
- 1	(3)	97.60	- 1	(64)	11,581
- 2	(5)	97.50	- 2	(128)	11,608
- 3	(8)	97.40	- 3	(192)	11,635
- 4	(10)	97.30	- 4	(256)	11,662
- 5	(13)	97.20	- 5	(320)	11,689
- 6	(15)	97.10	- 6	(383)	11,715
- 7	(18)	97.00	- 7	(447)	11,742
- 8	(20)	96.90	- 8	(511)	11,769
- 9	(23)	96.80	- 9	(575)	11,796
- 10	(25)	96.70	- 10	(639)	11,823
Weighting Factor:		0.000	Weighting Factor:		0.047

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	14	98.60	+ 10	613	11,127
+ 9	13	98.53	+ 9	552	11,154
+ 8	11	98.46	+ 8	490	11,181
+ 7	10	98.39	+ 7	429	11,208
+ 6	8	98.32	+ 6	368	11,235
+ 5	7	98.25	+ 5	307	11,262
+ 4	6	98.18	+ 4	245	11,288
+ 3	4	98.11	+ 3	184	11,315
+ 2	3	98.04	+ 2	123	11,342
+ 1	1	97.97	+ 1	61	11,369
				0	11,396
0	0	97.90	0	0	11,471
				0	11,546
- 1	(1)	97.81	- 1	(61)	11,573
- 2	(1)	97.72	- 2	(123)	11,600
- 3	(2)	97.63	- 3	(184)	11,627
- 4	(2)	97.54	- 4	(245)	11,654
- 5	(3)	97.45	- 5	(307)	11,681
- 6	(3)	97.36	- 6	(368)	11,707
- 7	(4)	97.27	- 7	(429)	11,734
- 8	(4)	97.18	- 8	(490)	11,761
- 9	(5)	97.09	- 9	(552)	11,788
- 10	(5)	97.00	- 10	(613)	11,815
Weighting Factor:		0.001	Weighting Factor:		0.045

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	159	76.40	+ 10	1,561	11,113
+ 9	143	76.24	+ 9	1,405	11,140
+ 8	127	76.08	+ 8	1,249	11,167
+ 7	111	75.92	+ 7	1,093	11,194
+ 6	95	75.76	+ 6	937	11,221
+ 5	80	75.60	+ 5	781	11,248
+ 4	64	75.44	+ 4	624	11,274
+ 3	48	75.28	+ 3	468	11,301
+ 2	32	75.12	+ 2	312	11,328
+ 1	16	74.96	+ 1	156	11,355
				0	11,382
0	0	74.80	0	0	11,457
				0	11,532
- 1	(28)	74.54	- 1	(156)	11,559
- 2	(55)	74.28	- 2	(312)	11,586
- 3	(83)	74.02	- 3	(468)	11,613
- 4	(110)	73.76	- 4	(624)	11,640
- 5	(138)	73.50	- 5	(781)	11,667
- 6	(166)	73.24	- 6	(937)	11,693
- 7	(193)	72.98	- 7	(1,093)	11,720
- 8	(221)	72.72	- 8	(1,249)	11,747
- 9	(248)	72.46	- 9	(1,405)	11,774
- 10	(276)	72.20	- 10	(1,561)	11,801
Weighting Factor:		0.012	Weighting Factor:		0.115

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	572	74.30	+ 10	3,119	10,363
+ 9	515	74.13	+ 9	2,807	10,388
+ 8	458	73.96	+ 8	2,495	10,412
+ 7	400	73.79	+ 7	2,183	10,437
+ 6	343	73.62	+ 6	1,871	10,461
+ 5	286	73.45	+ 5	1,560	10,486
+ 4	229	73.28	+ 4	1,248	10,510
+ 3	172	73.11	+ 3	936	10,535
+ 2	114	72.94	+ 2	624	10,559
+ 1	57	72.77	+ 1	312	10,584
				0	10,608
0	0	72.60	0	0	10,683
				0	10,758
- 1	(76)	72.33	- 1	(312)	10,783
- 2	(152)	72.06	- 2	(624)	10,807
- 3	(227)	71.79	- 3	(936)	10,832
- 4	(303)	71.52	- 4	(1,248)	10,856
- 5	(379)	71.25	- 5	(1,560)	10,881
- 6	(455)	70.98	- 6	(1,871)	10,905
- 7	(531)	70.71	- 7	(2,183)	10,930
- 8	(606)	70.44	- 8	(2,495)	10,954
- 9	(682)	70.17	- 9	(2,807)	10,979
- 10	(758)	69.90	- 10	(3,119)	11,003
Weighting Factor:		0.042	Weighting Factor:		0.230

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	50	95.50	+ 10	1,712	10,309
+ 9	45	95.31	+ 9	1,541	10,333
+ 8	40	95.12	+ 8	1,370	10,358
+ 7	35	94.93	+ 7	1,198	10,382
+ 6	30	94.74	+ 6	1,027	10,407
+ 5	25	94.55	+ 5	856	10,431
+ 4	20	94.36	+ 4	685	10,455
+ 3	15	94.17	+ 3	514	10,480
+ 2	10	93.98	+ 2	342	10,504
+ 1	5	93.79	+ 1	171	10,529
				0	10,553
0	0	93.60	0	0	10,628
				0	10,703
- 1	(7)	93.31	- 1	(171)	10,727
- 2	(13)	93.02	- 2	(342)	10,752
- 3	(20)	92.73	- 3	(514)	10,776
- 4	(27)	92.44	- 4	(685)	10,801
- 5	(34)	92.15	- 5	(856)	10,825
- 6	(40)	91.86	- 6	(1,027)	10,849
- 7	(47)	91.57	- 7	(1,198)	10,874
- 8	(54)	91.28	- 8	(1,370)	10,898
- 9	(60)	90.99	- 9	(1,541)	10,923
- 10	(67)	90.70	- 10	(1,712)	10,947
Weighting Factor:		0.004	Weighting Factor:		0.126

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	74	89.50	+ 10	1,556	10,217
+ 9	67	89.32	+ 9	1,400	10,241
+ 8	59	89.14	+ 8	1,245	10,265
+ 7	52	88.96	+ 7	1,089	10,289
+ 6	44	88.78	+ 6	934	10,313
+ 5	37	88.60	+ 5	778	10,338
+ 4	30	88.42	+ 4	622	10,362
+ 3	22	88.24	+ 3	467	10,386
+ 2	15	88.06	+ 2	311	10,410
+ 1	7	87.88	+ 1	156	10,434
				0	10,458
0	0	87.70	0	0	10,533
				0	10,608
- 1	(9)	87.43	- 1	(156)	10,632
- 2	(17)	87.16	- 2	(311)	10,656
- 3	(26)	86.89	- 3	(467)	10,680
- 4	(35)	86.62	- 4	(622)	10,704
- 5	(44)	86.35	- 5	(778)	10,729
- 6	(52)	86.08	- 6	(934)	10,753
- 7	(61)	85.81	- 7	(1,089)	10,777
- 8	(70)	85.54	- 8	(1,245)	10,801
- 9	(78)	85.27	- 9	(1,400)	10,825
- 10	(87)	85.00	- 10	(1,556)	10,849
Weighting Factor:		0.005	Weighting Factor:		0.115

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	131	85.80	+ 10	1,584	10,382
+ 9	118	85.63	+ 9	1,426	10,407
+ 8	105	85.46	+ 8	1,267	10,431
+ 7	92	85.29	+ 7	1,109	10,456
+ 6	79	85.12	+ 6	950	10,480
+ 5	66	84.95	+ 5	792	10,505
+ 4	52	84.78	+ 4	634	10,530
+ 3	39	84.61	+ 3	475	10,554
+ 2	26	84.44	+ 2	317	10,579
+ 1	13	84.27	+ 1	158	10,603
				0	10,628
0	0	84.10	0	0	10,703
				0	10,778
- 1	(17)	83.84	- 1	(158)	10,803
- 2	(34)	83.58	- 2	(317)	10,827
- 3	(52)	83.32	- 3	(475)	10,852
- 4	(69)	83.06	- 4	(634)	10,876
- 5	(86)	82.80	- 5	(792)	10,901
- 6	(103)	82.54	- 6	(950)	10,926
- 7	(120)	82.28	- 7	(1,109)	10,950
- 8	(138)	82.02	- 8	(1,267)	10,975
- 9	(155)	81.76	- 9	(1,426)	10,999
- 10	(172)	81.50	- 10	(1,584)	11,024
Weighting Factor:		0.010	Weighting Factor:		0.117

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2012 - December 2012

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	81	95.40	+ 10	1,667	10,311
+ 9	73	95.20	+ 9	1,500	10,335
+ 8	65	95.00	+ 8	1,334	10,360
+ 7	57	94.80	+ 7	1,167	10,384
+ 6	49	94.60	+ 6	1,000	10,409
+ 5	41	94.40	+ 5	834	10,433
+ 4	32	94.20	+ 4	667	10,457
+ 3	24	94.00	+ 3	500	10,482
+ 2	16	93.80	+ 2	333	10,506
+ 1	8	93.60	+ 1	167	10,531
				0	10,555
0	0	93.40	0	0	10,630
				0	10,705
- 1	(12)	93.11	- 1	(167)	10,729
- 2	(24)	92.82	- 2	(333)	10,754
- 3	(37)	92.53	- 3	(500)	10,778
- 4	(49)	92.24	- 4	(667)	10,803
- 5	(61)	91.95	- 5	(834)	10,827
- 6	(73)	91.66	- 6	(1,000)	10,851
- 7	(85)	91.37	- 7	(1,167)	10,876
- 8	(98)	91.08	- 8	(1,334)	10,900
- 9	(110)	90.79	- 9	(1,500)	10,925
- 10	(122)	90.50	- 10	(1,667)	10,949
Weighting Factor:		0.006	Weighting Factor:		0.123

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2012 - December 2012

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 4	0.0	97.7	98.4	96.7	$6	($25)	99.4	$6
Crist 5	0.1	97.9	98.6	97.0	$14	($5)	98.8	$14
Crist 6	1.2	74.8	76.4	72.2	$159	($276)	73.4	($148)
Crist 7	4.2	72.6	74.3	69.9	$572	($758)	75.5	$572
Smith 1	0.4	93.6	95.5	90.7	$50	($67)	92.6	($23)
Smith 2	0.5	87.7	89.5	85.0	$74	($87)	86.3	($45)
Daniel 1	1.0	84.1	85.8	81.5	$131	($172)	75.7	($172)
Daniel 2	0.6	93.4	95.4	90.5	$81	($122)	89.5	($122)
Total:	8.0							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 4	4.7	11,479	70.0	11,823	11,135	$639	($639)	11,722	($399)
Crist 5	4.5	11,471	66.7	11,815	11,127	$613	($613)	10,961	$613
Crist 6	11.5	11,457	57.8	11,801	11,113	$1,561	($1,561)	11,131	$1,456
Crist 7	23.0	10,683	80.0	11,003	10,363	$3,119	($3,119)	10,836	($992)
Smith 1	12.6	10,628	68.5	10,947	10,309	$1,712	($1,712)	10,211	$1,712
Smith 2	11.5	10,533	58.1	10,849	10,217	$1,556	($1,556)	10,310	$955
Daniel 1	11.7	10,703	57.2	11,024	10,382	$1,584	($1,584)	10,487	$908
Daniel 2	12.3	10,630	54.9	10,949	10,311	$1,667	($1,667)	10,495	$410
Total:	92.0								

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Actual Unit Performance Data

Gulf Power Company

Period of: January 2012 - December 2012

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 4	99.9	-0.5	99.4
Crist 5	99.0	-0.2	98.8
Crist 6	73.1	0.3	73.4
Crist 7	71.4	4.1	75.5
Smith 1	93.8	-1.2	92.6
Smith 2	95.6	-9.3	86.3
Daniel 1	80.4	-4.7	75.7
Daniel 2	95.7	-6.2	89.5

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 4	11,692	30	11,722
Crist 5	11,370	-409	10,961
Crist 6	10,709	422	11,131
Crist 7	11,387	-551	10,836
Smith 1	10,800	-589	10,211
Smith 2	11,104	-794	10,310
Daniel 1	10,439	48	10,487
Daniel 2	10,413	82	10,495

* Refer to pages 3 through 10, Schedule 2.

** Refer to pages 10 through 17, Schedule 3.

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 4	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	99.8	100.0	99.7	100.0	100.0	99.6	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	375.1	0.0	78.2	139.7	0.0	133.7	
4.	RSH	367.1	696.0	662.5	580.3	744.0	583.3	
5.	UH	1.8	0.0	2.3	0.0	0.0	3.1	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	1.8	0.0	2.3	0.0	0.0	3.1	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	
14.	Oper MBtu	201851	0	37394	71440	0	73692	
15.	Net Gen (MWH)	15827	0	3109	5896	0	6507	
16.	ANOHR (Btu/KWH)	12754	0	12028	12117	0	11325	
17.	NOF %	56.3	0.0	53.0	56.3	0.0	64.9	
18.	NPC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	
19.	ANOHR Equation	10^6 / AKW * [147.87 + 27.22 * JUL - 19.30 * NOV] + 8,647						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 4	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	100.0	100.0	99.6	99.7	100.0	100.0	99.9
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	0.0	0.0	0.4	0.0	555.1	744.0	2026.1
4.	RSH	744.0	744.0	716.7	742.0	165.9	0.0	6745.8
5.	UH	0.0	0.0	3.0	2.0	0.0	0.0	12.1
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	3.0	0.0	0.0	0.0	10.1
8.	MOH	0.0	0.0	0.0	2.0	0.0	0.0	2.0
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	75.0
14.	Oper MBtu	0	0	0	0	328983	448302	1161662
15.	Net Gen (MWH)	0	0	0	0	27967	40050	99356
16.	ANOHR (Btu/KWH)	0	0	0	0	11763	11194	11692
17.	NOF %	0.0	0.0	0.0	0.0	67.2	71.8	65.4
18.	NPC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	75.0

19.	ANOHR Equation	10^6 / AKW * [147.87 + 27.22 * JUL - 19.30 * NOV] + 8,647

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 5	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	100.0	100.0	94.3	97.9	99.8	100.0	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	440.3	696.0	677.8	583.5	742.8	720.0	
4.	RSH	303.7	0.0	23.2	121.3	0.0	0.0	
5.	UH	0.0	0.0	42.0	15.2	1.2	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	1.2	0.0	
8.	MOH	0.0	0.0	42.0	15.2	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	
14.	Oper MBtu	197405	325861	384889	323440	376195	387243	
15.	Net Gen (MWH)	18201	29099	32188	27682	35005	32165	
16.	ANOHR (Btu/KWH)	10846	11198	11958	11684	10747	12039	
17.	NOF %	55.1	55.7	63.3	63.3	62.8	59.6	
18.	NPC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	

19.	ANOHR Equation	10^6 / AKW * [332.39 - 15.75 * APR + 18.08 * JUL + 20.39 * AUG + 23.68 * SEP] + 1,068 + 0.06941 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 5	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	100.0	99.5	100.0	100.0	96.4	100.0	99.0
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	645.9	627.2	720.0	744.0	334.4	0.0	6932.0
4.	RSH	98.1	113.3	0.0	0.0	360.6	744.0	1764.2
5.	UH	0.0	3.5	0.0	0.0	26.0	0.0	87.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	1.2
8.	MOH	0.0	3.5	0.0	0.0	26.0	0.0	86.7
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	75.0
14.	Oper MBtu	358451	348950	334571	348442	150731	0	3536178
15.	Net Gen (MWH)	30902	31374	31827	29382	13182	0	311007
16.	ANCHR (Btu/KWH)	11600	11122	10512	11859	11435	0	11370
17.	NOF %	63.8	66.7	58.9	52.7	52.6	0.0	59.8
18.	NPC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	75.0
19.	ANOHR Equation	10^6 / AKW * [332.39 - 15.75 * APR + 18.08 * JUL + 20.39 * AUG + 23.68 * SEP] + 1,068 + 0.06941 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 6	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	100.0	10.3	0.0	21.8	100.0	88.3	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	119.9	0.0	0.0	156.8	744.0	537.1	
4.	RSH	624.1	72.0	0.0	0.0	0.0	98.9	
5.	UH	0.0	624.0	743.0	563.2	0.0	84.0	
6.	POH	0.0	624.0	743.0	563.2	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	84.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	291.0	291.0	291.0	291.0	300.0	300.0	
14.	Oper MBtu	205566	0	0	276623	1607811	1238879	
15.	Net Gen (MWH)	17291	0	0	22677	156777	119706	
16.	ANOHR (Btu/KWH)	11889	0	0	12198	10255	10349	
17.	NOF %	49.6	0.0	0.0	49.7	70.2	74.3	
18.	NPC (MW)	291.0	291.0	291.0	291.0	300.0	300.0	

19.	ANOHR Equation	10^6 / AKW * [803.77 + 53.22 * AUG + 61.67 * SEP + 128.86 * OCT - 57.18 * NOV] + 3,660 + 0.01561 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 6	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	100.0	96.9	94.1	90.6	74.9	95.7	73.1
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	273.2	385.5	684.0	674.2	556.5	502.3	4633.3
4.	RSH	470.9	335.5	0.0	0.0	0.0	209.8	1811.1
5.	UH	0.0	23.1	36.0	69.9	164.5	32.0	2339.6
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1930.2
7.	FOH	0.0	0.0	26.5	0.0	30.4	0.0	56.9
8.	MOH	0.0	23.1	9.5	69.9	134.1	32.0	352.4
9.	PFOH	0.1	0.0	0.0	0.0	41.2	0.0	41.3
10.	LR pf (MW)	152.0	0.0	0.0	0.0	122.2	0.0	122.2
11.	PMOH	0.0	0.0	14.1	0.0	0.0	0.0	14.1
12.	LR pm (MW)	0.0	0.0	138.0	0.0	0.0	0.0	138.0
13.	NSC (MW)	300.0	300.0	300.0	300.0	300.0	300.0	297.0
14.	Oper MBtu	601592	917053	1447035	1427342	1069856	1066368	9858125
15.	Net Gen (MWH)	57513	79215	134551	132182	98860	101790	920562
16.	ANOHR (Btu/KWH)	10460	11577	10755	10798	10822	10476	10709
17.	NOF %	70.2	68.5	65.6	65.4	59.2	67.6	66.9
18.	NPC (MW)	300.0	300.0	300.0	300.0	300.0	300.0	297.0

19.	ANOHR Equation	10^6 / AKW * [803.77 + 53.22 * AUG + 61.67 * SEP + 128.86 * OCT - 57.18 * NOV] + 3,660 + 0.01561 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 7	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	92.0	100.0	100.0	96.0	99.9	92.6	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	635.9	696.0	743.0	677.2	482.8	666.8	
4.	RSH	48.4	0.0	0.0	35.9	261.2	0.0	
5.	UH	59.7	0.0	0.0	6.9	0.0	53.2	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	10.0	0.0	0.0	6.9	0.0	0.0	
8.	MOH	49.7	0.0	0.0	0.0	0.0	53.2	
9.	PFOH	0.0	0.0	0.0	43.5	1.5	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	235.0	135.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	465.0	465.0	465.0	465.0	465.0	465.0	
14.	Oper MBtu	1865982	2036182	2178843	2033922	1620433	2050458	
15.	Net Gen (MWH)	163186	178586	191799	174070	134669	186127	
16.	ANOHR (Btu/KWH)	11435	11402	11360	11685	12033	11016	
17.	NOF %	55.2	55.2	55.5	55.3	60.0	60.0	
18.	NPC (MW)	465.0	465.0	465.0	465.0	465.0	465.0	
19.	ANOHR Equation	10^6 / AKW * [1509.41 - 103.64 * JAN - 97.39 * FEB + 123.28 * APR + 64.40 * SEP - 94.54 * OCT - 86.63 * NOV] + 2,982 + 0.00932 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	CRIST 7	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	91.3	99.6	46.7	0.0	0.0	38.6	71.4
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	698.3	697.4	0.0	0.0	0.0	287.2	5584.6
4.	RSH	0.0	43.7	336.0	0.0	0.0	0.0	725.3
5.	UH	45.8	2.9	384.0	744.0	721.0	456.8	2474.1
6.	POH	0.0	0.0	384.0	744.0	721.0	456.8	2305.8
7.	FOH	0.0	2.9	0.0	0.0	0.0	0.0	19.7
8.	MOH	45.8	0.0	0.0	0.0	0.0	0.0	148.6
9.	PFOH	49.0	0.0	0.0	0.0	0.0	0.0	94.1
10.	LR pf (MW)	174.8	0.0	0.0	0.0	0.0	0.0	202.0
11.	PMOH	3.9	0.0	0.0	0.0	0.0	0.0	3.9
12.	LR pm (MW)	83.0	0.0	0.0	0.0	0.0	0.0	83.0
13.	NSC (MW)	465.0	465.0	465.0	472.0	472.0	472.0	466.8
14.	Oper MBtu	2172732	2044885	0	0	0	873038	16876475
15.	Net Gen (MWH)	190868	188298	0	0	0	74439	1482042
16.	ANOHR (Btu/KWH)	11383	10860	0	0	0	11728	11387
17.	NOF %	58.8	58.1	0.0	0.0	0.0	54.9	56.9
18.	NPC (MW)	465.0	465.0	465.0	472.0	472.0	472.0	466.8
19.	ANOHR Equation	10^6 / AKW * [1509.41 - 103.64 * JAN - 97.39 * FEB + 123.28 * APR + 64.40 * SEP - 94.54 * OCT - 86.63 * NOV] + 2,982 + 0.00932 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	SMITH 1	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	100.0	100.0	99.2	77.3	96.9	100.0	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	744.0	696.0	737.4	561.0	431.2	720.0	
4.	RSH	0.0	0.0	0.0	0.0	289.9	0.0	
5.	UH	0.0	0.0	5.6	159.0	22.9	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	5.6	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	159.0	22.9	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	6.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	130.0	0.0	0.0	
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
14.	Oper MBtu	583746	547147	556377	450740	346906	561353	
15.	Net Gen (MWH)	54180	50839	51780	42123	32679	52221	
16.	ANOHR (Btu/KWH)	10774	10762	10745	10701	10616	10750	
17.	NOF %	45.0	45.1	43.3	46.3	46.8	44.8	
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [128.19 + 10.27 * JUL] + 9,465

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	SMITH 1	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	95.5	99.2	60.8	100.0	95.4	100.0	93.8
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	710.7	740.9	291.4	0.0	431.8	744.0	6808.4
4.	RSH	0.0	0.0	147.6	744.0	256.3	0.0	1437.9
5.	UH	33.4	3.1	281.0	0.0	32.9	0.0	537.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	33.4	3.1	0.0	0.0	32.9	0.0	75.0
8.	MOH	0.0	0.0	281.0	0.0	0.0	0.0	462.8
9.	PFOH	0.0	6.4	2.3	0.0	0.0	0.0	8.7
10.	LR pf (MW)	0.0	67.7	98.4	0.0	0.0	0.0	75.9
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	6.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	130.0
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
14.	Oper MBtu	626548	578870	239045	0	337596	613860	5442188
15.	Net Gen (MWH)	57991	52471	21638	0	31273	56702	503897
16.	ANOHR (Btu/KWH)	10804	11032	11047	0	10795	10826	10800
17.	NOF %	50.4	43.7	45.8	0.0	44.7	47.0	45.7
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19.	ANOHR Equation	10^6 / AKW * [128.19 + 10.27 * JUL] + 9,465

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	SMITH 2	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	100.0	86.1	100.0	100.0	99.9	100.0	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	0.0	0.0	0.0	490.1	653.1	0.0	
4.	RSH	744.0	599.4	743.0	229.9	90.9	720.0	
5.	UH	0.0	96.6	0.0	0.0	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	96.6	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	1.3	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	131.0	0.0	
13.	NSC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	
14.	Oper MBtu	0	0	0	409174	548299	0	
15.	Net Gen (MWH)	0	0	0	38968	51135	0	
16.	ANOHR (Btu/KWH)	0	0	0	10500	10723	0	
17.	NOF %	0.0	0.0	0.0	40.8	40.2	0.0	
18.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	

19.	ANOHR Equation	10^6 / AKW * [320.27 + 28.73 * JAN - 24.84 * MAY - 26.36 * OCT - 15.30 * NOV] + 5,898 + 0.01509 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	SMITH 2	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	99.8	94.5	100.0	100.0	100.0	67.1	95.6
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	691.9	744.0	720.0	744.0	468.9	0.0	4511.9
4.	RSH	52.1	0.0	0.0	0.0	252.1	499.0	3930.5
5.	UH	0.0	0.0	0.0	0.0	0.0	245.0	341.6
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	MOH	0.0	0.0	0.0	0.0	0.0	245.0	341.6
9.	PFOH	2.0	0.5	0.0	0.0	0.0	0.0	2.5
10.	LR pf (MW)	115.0	193.0	0.0	0.0	0.0	0.0	129.3
11.	PMOH	1.0	82.7	0.0	0.0	0.0	0.0	85.0
12.	LR pm (MW)	125.0	96.0	0.0	0.0	0.0	0.0	96.9
13.	NSC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	195.0
14.	Oper MBtu	619958	593848	592618	592729	377154	0	3733780
15.	Net Gen (MWH)	55409	51886	51705	52751	34407	0	336261
16.	ANOHR (Btu/KWH)	11189	11445	11462	11236	10962	0	11104
17.	NOF %	41.1	35.8	36.8	36.4	37.6	0.0	38.2
18.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	195.0

19.	ANOHR Equation	10^6 / AKW * [320.27 + 28.73 * JAN - 24.84 * MAY - 26.36 * OCT - 15.30 * NOV] + 5,898 + 0.01509 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	DANIEL 1	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	75.9	100.0	55.5	0.0	78.5	100.0	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	115.0	0.0	98.9	0.0	266.4	382.4	
4.	RSH	449.8	696.0	314.1	0.0	317.5	337.7	
5.	UH	179.2	0.0	330.0	720.0	160.1	0.0	
6.	POH	0.0	0.0	330.0	720.0	160.1	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	179.2	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	3.1	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	110.2	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	
14.	Oper MBtu	417919	0	314574	0	871153	1185099	
15.	Net Gen (MWH)	41008	0	31988	0	79357	117594	
16.	ANOHR (Btu/KWH)	10191	0	9834	0	10978	10078	
17.	NOF %	69.9	0.0	63.4	0.0	58.4	60.3	
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [521.83 + 65.51 * JAN + 59.16 * JUL] + 8,889

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	DANIEL 1	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	99.9	98.6	100.0	99.4	81.8	75.3	80.4
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	744.0	628.3	0.0	73.7	450.7	0.0	2759.4
4.	RSH	0.0	115.7	720.0	670.3	150.3	560.0	4331.4
5.	UH	0.0	0.0	0.0	0.0	120.0	184.0	1693.3
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1210.1
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	MOH	0.0	0.0	0.0	0.0	120.0	184.0	483.2
9.	PFOH	1.6	16.3	0.0	12.0	73.8	0.0	106.8
10.	LR pf (MW)	118.3	322.6	0.0	201.2	77.9	0.0	130.6
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
14.	Oper MBtu	2671408	1428270	0	283351	1703026	0	8874801
15.	Net Gen (MWH)	260016	127713	0	24315	168166	0	850157
16.	ANOHR (Btu/KWH)	10274	11183	0	11653	10127	0	10439
17.	NOF %	68.5	39.9	0.0	64.7	73.2	0.0	60.4
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [521.83 + 65.51 * JAN + 59.16 * JUL] + 8,889

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	DANIEL 2	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Jun '12	
1.	EAF (%)	99.7	100.0	99.3	99.8	100.0	99.9	
2.	PH	744.0	696.0	743.0	720.0	744.0	720.0	
3.	SH	322.9	0.0	541.9	718.8	430.0	237.6	
4.	RSH	421.2	696.0	197.1	0.0	314.0	482.4	
5.	UH	0.0	0.0	4.0	1.2	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	4.0	1.2	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	8.5	0.0	8.3	0.3	0.0	1.1	
10.	LR pf (MW)	138.5	0.0	72.1	10.0	0.0	505.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	
14.	Oper MBtu	1079465	0	2099074	2750670	1119175	488298	
15.	Net Gen (MWH)	109302	0	203848	275492	102740	46683	
16.	ANOHR (Btu/KWH)	9876	0	10297	9985	10893	10460	
17.	NOF %	66.4	0.0	73.8	75.1	46.9	38.5	
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [24.52 - 110.71 * JAN - 49.24 * JUL - 56.45 * SEP - 73.43 * OCT] + 11,929 - 0.00393 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2012 - December 2012

	DANIEL 2	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Total
1.	EAF (%)	100.0	97.8	87.5	91.1	83.2	89.8	95.7
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8784.0
3.	SH	403.1	594.5	0.0	0.0	0.0	0.0	3248.8
4.	RSH	340.9	146.6	630.3	678.0	600.0	668.0	5174.4
5.	UH	0.0	2.9	89.8	66.0	121.0	76.0	360.8
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	5.2
8.	MOH	0.0	2.9	89.8	66.0	121.0	76.0	355.6
9.	PFOH	0.0	25.4	0.0	0.0	0.0	0.0	43.6
10.	LR pf (MW)	0.0	267.2	0.0	0.0	0.0	0.0	209.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
14.	Oper MBtu	1019796	1344468	0	0	0	0	9900946
15.	Net Gen (MWH)	92898	119819	0	0	0	0	950782
16.	ANOHR (Btu/KWH)	10978	11221	0	0	0	0	10413
17.	NOF %	45.2	39.5	0.0	0.0	0.0	0.0	57.4
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [24.52 - 110.71 * JAN - 49.24 * JUL - 56.45 * SEP - 73.43 * OCT] + 11,929 - 0.00393 * LSRF / AKW

Issued by: S. W. Connally, Jr.

Planned Outage Schedules (Actual)

Period of: January 2012 - December 2012

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

Issued by: S. W. Connally, Jr.

EXHIBIT TO THE TESTIMONY OF

M. A. YOUNG, III

IN FPSC DOCKET 130001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 45
PARTY Gulf Power Company (Gulf) (Direct)
DESCRIPTION M.A. Young - MAY-2

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Crist 5 ANOHR = 10^6 / AKW * [230.19 + 12.41 * JUN + 16.35 * JUL + 17.53 * OCT]

+ 3,801 + 0.05350 * LSRF / AKW

Crist 6 ANOHR = 10^6 / AKW * [1012.40 + 50.51 * APR - 115.89 * MAY + 67.27 * JUL - 67.36 * NOV]

+ 1,428 + 0.02148 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [1373.91 - 101.46 * MAR + 164.88 * APR]

+ 3,451 + 0.00908 * LSRF / AKW

Smith 1 ANOHR = 10^6 / AKW * [59.93 + 11.03 * MAR + 6.71 * MAY + 9.25 * JUN + 11.47 * JUL + 12.00 * AUG + 16.27 * OCT]

+ 10,004

Smith 2 ANOHR = 10^6 / AKW * [89.09 - 19.11 * JAN - 36.70 * MAR - 27.06 * APR - 20.50 * MAY - 19.52 * NOV]

+ 10,035

Smith 3 ANOHR = 10^6 / AKW * [284.85 + 32.50 * JUL - 45.08 * OCT]

+ 6,495 - 0.00002 * LSRF / AKW

Where:

ANOHR = Average Net Operating Heat Rate, BTU/KWH
AKW = Average Kilowatt Load, KW
LSRF = Load Square Range Factor, KW^2
BTU/LB = Coal Burned Average Heat Content, BTU/LB
JAN = January, 0 if not January, 1 if January
FEB = February, 0 if not February, 1 if February
MAR = March, 0 if not March, 1 if March
APR = April, 0 if not April, 1 if April
MAY = May, 0 if not May, 1 if May
JUN = June, 0 if not June, 1 if June
JUL = July, 0 if not July, 1 if July
AUG = August, 0 if not August, 1 if August
SEP = September, 0 if not September, 1 if September
OCT = October, 0 if not October, 1 if October
NOV = November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11394	168	57.7	3524	0	0	0	0	0	0	1	0	0	0	0	0	2010
11343	168	60.5	3865	0	0	0	0	0	0	1	0	0	0	0	0	2010
11481	168	55.0	3220	0	0	0	0	0	0	1	0	0	0	0	0	2010
11338	168	60.0	3797	0	0	0	0	0	0	1	0	0	0	0	0	2010
11618	168	59.1	3688	0	0	0	0	0	0	0	1	0	0	0	0	2010
11617	168	59.3	3745	0	0	0	0	0	0	0	1	0	0	0	0	2010
11267	168	58.2	3586	0	0	0	0	0	0	0	1	0	0	0	0	2010
10840	168	58.2	3530	0	0	0	0	0	0	0	1	0	0	0	0	2010
11320	168	54.0	3007	0	0	0	0	0	0	0	1	0	0	0	0	2010
11113	168	58.5	3513	0	0	0	0	0	0	0	0	1	0	0	0	2010
11852	168	60.5	3886	0	0	0	0	0	0	0	0	1	0	0	0	2010
12081	168	59.0	3702	0	0	0	0	0	0	0	0	1	0	0	0	2010
12536	168	45.4	2193	0	0	0	0	0	0	0	0	1	0	0	0	2010
13578	27	36.0	1500	0	0	0	0	0	0	0	0	0	1	0	1	2010
*10085	163	47.3	3086	0	0	0	0	0	0	0	0	0	1	0	0	2010
12190	168	47.9	2465	0	0	0	0	0	0	0	0	0	1	0	0	2010
12329	168	48.5	2542	0	0	0	0	0	0	0	0	0	1	0	0	2010
12387	168	40.7	1655	0	0	0	0	0	0	0	0	0	1	0	0	2010
11611	169	50.2	2547	0	0	0	0	0	0	0	0	0	0	1	0	2010
11036	168	50.0	2516	0	0	0	0	0	0	0	0	0	0	1	0	2010
10842	166	57.1	3422	0	0	0	0	0	0	0	0	0	0	1	0	2010
11454	168	64.3	4265	0	0	0	0	0	0	0	0	0	0	1	0	2010
12085	105	62.0	4008	0	0	0	0	0	0	0	0	0	0	0	0	2010
11124	73	59.1	3707	1	0	0	0	0	0	0	0	0	0	0	1	2011
10667	168	66.4	4503	1	0	0	0	0	0	0	0	0	0	0	0	2011
10560	168	68.0	4732	1	0	0	0	0	0	0	0	0	0	0	0	2011
10697	168	66.7	4575	1	0	0	0	0	0	0	0	0	0	0	0	2011
10867	168	64.2	4262	0	1	0	0	0	0	0	0	0	0	0	0	2011
10546	168	60.8	3749	0	1	0	0	0	0	0	0	0	0	0	0	2011
11132	167	61.1	3867	0	1	0	0	0	0	0	0	0	0	0	0	2011
11007	168	63.9	4224	0	1	0	0	0	0	0	0	0	0	0	0	2011
10969	168	63.6	4201	0	0	1	0	0	0	0	0	0	0	0	0	2011
11022	84	60.8	3941	0	0	1	0	0	0	0	0	0	0	0	0	2011
10912	104	58.5	3683	0	0	1	0	0	0	0	0	0	0	0	1	2011
10403	168	65.9	4486	0	0	1	0	0	0	0	0	0	0	0	0	2011
10403	168	65.2	4413	0	0	0	1	0	0	0	0	0	0	0	0	2011
10275	168	65.9	4504	0	0	0	1	0	0	0	0	0	0	0	0	2011
10525	168	64.8	4364	0	0	0	1	0	0	0	0	0	0	0	0	2011
10910	168	58.6	3645	0	0	0	1	0	0	0	0	0	0	0	0	2011
11381	168	51.4	2850	0	0	0	0	1	0	0	0	0	0	0	0	2011
11128	168	47.5	2373	0	0	0	0	1	0	0	0	0	0	0	0	2011
11324	168	40.8	1690	0	0	0	0	1	0	0	0	0	0	0	0	2011
11277	168	47.3	2367	0	0	0	0	1	0	0	0	0	0	0	0	2011
11277	168	54.5	3198	0	0	0	0	1	0	0	0	0	0	0	0	2011
11672	168	54.6	3213	0	0	0	0	0	1	0	0	0	0	0	0	2011
11844	168	54.3	3197	0	0	0	0	0	1	0	0	0	0	0	0	2011
11439	168	50.4	2702	0	0	0	0	0	1	0	0	0	0	0	0	2011

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11532	144	48.3	2480	0	0	0	0	0	1	0	0	0	0	0	0	2011
12006	168	49.5	2645	0	0	0	0	0	0	1	0	0	0	0	0	2011
11828	168	51.1	2787	0	0	0	0	0	0	1	0	0	0	0	0	2011
11209	168	54.5	3106	0	0	0	0	0	0	1	0	0	0	0	0	2011
10488	168	60.8	3744	0	0	0	0	0	0	1	0	0	0	0	0	2011
10314	168	61.6	3835	0	0	0	0	0	0	0	1	0	0	0	0	2011
11118	168	55.4	3295	0	0	0	0	0	0	0	1	0	0	0	0	2011
11377	168	57.9	3590	0	0	0	0	0	0	0	1	0	0	0	0	2011
11281	168	56.1	3363	0	0	0	0	0	0	0	1	0	0	0	0	2011
11569	168	50.2	2696	0	0	0	0	0	0	0	1	0	0	0	0	2011
11021	168	44.5	2045	0	0	0	0	0	0	0	0	1	0	0	0	2011
11081	168	50.6	2739	0	0	0	0	0	0	0	0	1	0	0	0	2011
11180	85	54.0	3361	0	0	0	0	0	0	0	0	0	0	0	1	2011
10511	168	52.9	2921	0	0	0	0	0	0	0	0	0	0	0	0	2011
11283	168	45.6	2126	0	0	0	0	0	0	0	0	0	0	0	0	2011
10777	168	45.5	2097	0	0	0	0	0	0	0	0	0	0	0	0	2011
10849	24	40.9	1672	0	0	0	0	0	0	0	0	0	0	0	0	2011
*9502	168	42.4	1839	1	0	0	0	0	0	0	0	0	0	0	0	2012
11048	85	40.4	1635	1	0	0	0	0	0	0	0	0	0	0	0	2012
12094	116	40.1	1671	1	0	0	0	0	0	0	0	0	0	0	1	2012
12267	168	40.6	1663	0	1	0	0	0	0	0	0	0	0	0	0	2012
11234	168	43.8	1958	0	1	0	0	0	0	0	0	0	0	0	0	2012
10713	168	40.8	1672	0	1	0	0	0	0	0	0	0	0	0	0	2012
10857	168	39.9	1596	0	1	0	0	0	0	0	0	0	0	0	0	2012
11421	168	49.3	2608	0	1	0	0	0	0	0	0	0	0	0	0	2012
11655	168	52.4	2994	0	0	1	0	0	0	0	0	0	0	0	0	2012
11846	167	52.1	2953	0	0	1	0	0	0	0	0	0	0	0	0	2012
12397	168	39.8	1590	0	0	1	0	0	0	0	0	0	0	0	0	2012
12522	103	39.6	1574	0	0	1	0	0	0	0	0	0	0	0	0	2012
12493	31	38.7	1514	0	0	0	1	0	0	0	0	0	0	0	1	2012
11642	168	51.9	2925	0	0	0	1	0	0	0	0	0	0	0	0	2012
11716	168	50.3	2748	0	0	0	1	0	0	0	0	0	0	0	0	2012
11653	168	40.1	1619	0	0	0	1	0	0	0	0	0	0	0	0	2012
10909	168	44.0	2015	0	0	0	0	1	0	0	0	0	0	0	0	2012
10598	168	49.0	2574	0	0	0	0	1	0	0	0	0	0	0	0	2012
12205	167	41.6	1763	0	0	0	0	1	0	0	0	0	0	0	0	2012
*10098	168	52.9	2979	0	0	0	0	1	0	0	0	0	0	0	0	2012
10899	168	51.0	2781	0	0	0	0	0	1	0	0	0	0	0	0	2012
12488	168	44.0	2059	0	0	0	0	0	1	0	0	0	0	0	0	2012
10790	168	43.2	1887	0	0	0	0	0	1	0	0	0	0	0	0	2012
12273	168	46.5	2299	0	0	0	0	0	1	0	0	0	0	0	0	2012
12532	168	43.3	1929	0	0	0	0	0	1	0	0	0	0	0	0	2012
12234	168	40.4	1656	0	0	0	0	0	0	1	0	0	0	0	0	2012
10923	168	46.6	2184	0	0	0	0	0	0	1	0	0	0	0	0	2012
11766	168	51.9	2715	0	0	0	0	0	0	1	0	0	0	0	0	2012
11538	142	53.3	2937	0	0	0	0	0	0	1	0	0	0	0	0	2012
10924	147	52.9	2931	0	0	0	0	0	0	0	1	0	0	0	1	2012

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11176	168	54.4	3107	0	0	0	0	0	0	0	1	0	0	0	0	2012
11324	168	44.6	2089	0	0	0	0	0	0	0	1	0	0	0	0	2012
10927	168	49.3	2596	0	0	0	0	0	0	0	1	0	0	0	0	2012
10927	168	49.3	2596	0	0	0	0	0	0	0	1	0	0	0	0	2012
*10447	168	40.8	1672	0	0	0	0	0	0	0	0	1	0	0	0	2012
10611	168	41.3	1727	0	0	0	0	0	0	0	0	1	0	0	0	2012
11040	168	42.0	1864	0	0	0	0	0	0	0	0	1	0	0	0	2012
12377	168	38.6	1506	0	0	0	0	0	0	0	0	0	1	0	0	2012
11435	168	39.9	1592	0	0	0	0	0	0	0	0	0	1	0	0	2012
11620	168	39.8	1584	0	0	0	0	0	0	0	0	0	1	0	0	2012
11865	168	39.6	1571	0	0	0	0	0	0	0	0	0	1	0	0	2012
11854	168	39.0	1526	0	0	0	0	0	0	0	0	0	1	0	0	2012
11568	169	39.2	1541	0	0	0	0	0	0	0	0	0	0	1	0	2012
10987	94	40.6	1668	0	0	0	0	0	0	0	0	0	0	1	0	2012
11613	125	41.6	1769	1	0	0	0	0	0	0	0	0	0	0	1	2013
11313	168	45.7	2105	1	0	0	0	0	0	0	0	0	0	0	0	2013
11051	168	54.0	2919	1	0	0	0	0	0	0	0	0	0	0	0	2013
10872	168	54.2	2935	1	0	0	0	0	0	0	0	0	0	0	0	2013
11096	168	54.3	2955	0	1	0	0	0	0	0	0	0	0	0	0	2013
11145	168	56.3	3203	0	1	0	0	0	0	0	0	0	0	0	0	2013
10969	168	55.7	3117	0	1	0	0	0	0	0	0	0	0	0	0	2013
10727	168	55.0	3029	0	1	0	0	0	0	0	0	0	0	0	0	2013
10459	168	56.4	3194	0	0	1	0	0	0	0	0	0	0	0	0	2013
10791	167	54.1	2932	0	0	1	0	0	0	0	0	0	0	0	0	2013
11363	168	53.7	2886	0	0	1	0	0	0	0	0	0	0	0	0	2013
12012	168	41.5	1731	0	0	1	0	0	0	0	0	0	0	0	0	2013
11898	168	40.6	1654	0	0	1	0	0	0	0	0	0	0	0	0	2013
11691	168	40.7	1663	0	0	0	1	0	0	0	0	0	0	0	0	2013
11991	168	40.1	1612	0	0	0	1	0	0	0	0	0	0	0	0	2013
11139	168	50.6	2619	0	0	0	1	0	0	0	0	0	0	0	0	2013
11340	168	57.2	3341	0	0	0	1	0	0	0	0	0	0	0	0	2013
10561	168	57.1	3297	0	0	0	0	1	0	0	0	0	0	0	0	2013
10843	168	54.6	2985	0	0	0	0	1	0	0	0	0	0	0	0	2013
11057	168	57.1	3289	0	0	0	0	1	0	0	0	0	0	0	0	2013
11536	168	51.9	2699	0	0	0	0	1	0	0	0	0	0	0	0	2013
11601	168	50.3	2535	0	0	0	0	1	0	0	0	0	0	0	0	2013
11419	168	43.0	1886	0	0	0	0	0	1	0	0	0	0	0	0	2013
10866	168	52.0	2876	0	0	0	0	0	1	0	0	0	0	0	0	2013
10647	8	66.0	4618	0	0	0	0	0	1	0	0	0	0	0	0	2013
10647	8	66.0	4618	0	0	0	0	0	1	0	0	0	0	0	0	2013

Data Base for CRIST 5 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hour	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
Year	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11267	109	222.7	54699	0	0	0	0	0	1	0	0	0	0	0	1	2010
11806	168	224.6	55565	0	0	0	0	0	0	1	0	0	0	0	0	2010
11800	140	234.3	59235	0	0	0	0	0	0	1	0	0	0	0	1	2010
11601	168	222.7	53860	0	0	0	0	0	0	1	0	0	0	0	0	2010
11836	168	219.5	52860	0	0	0	0	0	0	1	0	0	0	0	0	2010
11519	168	216.4	51070	0	0	0	0	0	0	0	1	0	0	0	0	2010
11182	168	207.8	47792	0	0	0	0	0	0	0	1	0	0	0	0	2010
11293	168	217.4	51935	0	0	0	0	0	0	0	1	0	0	0	0	2010
11232	168	215.2	50971	0	0	0	0	0	0	0	1	0	0	0	0	2010
11325	168	207.3	47212	0	0	0	0	0	0	0	1	0	0	0	0	2010
11632	167	203.2	46045	0	0	0	0	0	0	0	0	1	0	0	0	2010
11671	157	215.1	50939	0	0	0	0	0	0	0	0	1	0	0	0	2010
11562	145	220.9	53687	0	0	0	0	0	0	0	0	1	0	0	1	2010
11282	82	188.1	38937	0	0	0	0	0	0	0	0	1	0	0	0	2010
13337	94	120.7	15518	0	0	0	0	0	0	0	0	0	1	0	1	2010
13176	13	124.3	15694	0	0	0	0	0	0	0	0	0	1	0	0	2010
14892	10	115.0	14008	0	0	0	0	0	0	0	0	0	0	1	1	2010
12196	44	131.5	18870	0	0	0	0	0	0	0	0	0	0	1	0	2010
12027	89	192.0	43073	0	0	0	0	0	0	0	0	0	0	0	1	2010
11003	168	220.6	51784	0	0	0	0	0	0	0	0	0	0	0	0	2010
11148	133	231.6	57024	0	0	0	0	0	0	0	0	0	0	0	1	2010
11205	168	246.7	63884	0	0	0	0	0	0	0	0	0	0	0	0	2010
11182	24	250.6	126	0	0	0	0	0	0	0	0	0	0	0	0	2010
11096	168	216.7	49875	1	0	0	0	0	0	0	0	0	0	0	0	2011
10848	168	241.6	60463	1	0	0	0	0	0	0	0	0	0	0	0	2011
10737	168	245.4	62274	1	0	0	0	0	0	0	0	0	0	0	0	2011
10994	168	194.8	38897	1	0	0	0	0	0	0	0	0	0	0	0	2011
11281	168	178.8	32744	0	1	0	0	0	0	0	0	0	0	0	0	2011
10999	156	187.1	36227	0	1	0	0	0	0	0	0	0	0	0	0	2011
12995	55	123.3	16488	0	0	0	0	1	0	0	0	0	0	0	1	2011
11186	165	176.0	35869	0	0	0	0	1	0	0	0	0	0	0	1	2011
11893	64	154.2	27626	0	0	0	0	1	0	0	0	0	0	0	2	2011
11038	168	187.0	38870	0	0	0	0	0	1	0	0	0	0	0	0	2011
11096	164	196.8	44753	0	0	0	0	0	1	0	0	0	0	0	0	2011
11288	119	191.7	42793	0	0	0	0	0	1	0	0	0	0	0	1	2011
11808	144	148.2	24295	0	0	0	0	0	1	0	0	0	0	0	0	2011
11992	108	166.0	31680	0	0	0	0	0	0	1	0	0	0	0	1	2011
12017	168	162.2	29049	0	0	0	0	0	0	1	0	0	0	0	0	2011
12302	168	137.3	19866	0	0	0	0	0	0	1	0	0	0	0	0	2011
11797	93	152.0	23793	0	0	0	0	0	0	1	0	0	0	0	0	2011
11856	161	150.7	25323	0	0	0	0	0	0	0	1	0	0	0	1	2011
11632	54	173.0	34919	0	0	0	0	0	0	0	1	0	0	0	1	2011
11171	168	178.2	35342	0	0	0	0	0	0	0	1	0	0	0	0	2011
11212	168	172.8	32908	0	0	0	0	0	0	0	1	0	0	0	0	2011
11098	168	183.3	37552	0	0	0	0	0	0	0	1	0	0	0	0	2011
11855	163	135.8	19869	0	0	0	0	0	0	0	0	1	0	0	0	2011
11625	168	153.7	26369	0	0	0	0	0	0	0	0	1	0	0	0	2011

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11604	168	155.7	27090	0	0	0	0	0	0	0	0	1	0	0	0	2011
11198	136	166.3	32011	0	0	0	0	0	0	0	0	1	0	0	1	2011
11975	168	127.2	16651	0	0	0	0	0	0	0	0	0	1	0	0	2011
12182	168	134.5	18587	0	0	0	0	0	0	0	0	0	1	0	0	2011
12317	168	124.3	15560	0	0	0	0	0	0	0	0	0	1	0	0	2011
12343	164	122.2	15044	0	0	0	0	0	0	0	0	0	1	0	0	2011
12250	76	119.6	14538	0	0	0	0	0	0	0	0	0	0	1	1	2011
11456	140	136.7	20466	0	0	0	0	0	0	0	0	0	0	1	1	2011
11800	72	128.6	16878	0	0	0	0	0	0	0	0	0	0	0	0	2011
11952	140	137.1	19829	0	0	0	0	0	0	0	0	0	0	0	1	2011
12056	168	132.1	18221	0	0	0	0	0	0	0	0	0	0	0	0	2011
12084	168	126.0	16071	0	0	0	0	0	0	0	0	0	0	0	0	2011
12017	24	124.9	15682	0	0	0	0	0	0	0	0	0	0	0	0	2011
11889	120	144.1	22044	1	0	0	0	0	0	0	0	0	0	0	0	2012
12270	106	145.2	26039	0	0	0	1	0	0	0	0	0	0	0	1	2012
11057	168	173.2	34715	0	0	0	0	1	0	0	0	0	0	0	0	2012
10426	168	193.0	40563	0	0	0	0	1	0	0	0	0	0	0	0	2012
10227	168	216.0	48109	0	0	0	0	1	0	0	0	0	0	0	0	2012
10091	168	241.8	59959	0	0	0	0	1	0	0	0	0	0	0	0	2012
10091	168	241.8	59959	0	0	0	0	1	0	0	0	0	0	0	0	2012
*8718	168	213.1	45408	0	0	0	0	1	0	0	0	0	0	0	0	2012
10915	168	218.4	48094	0	0	0	0	0	1	0	0	0	0	0	0	2012
10660	153	223.6	51774	0	0	0	0	0	1	0	0	0	0	0	0	2012
*11033	33	180.5	36522	0	0	0	0	0	0	1	0	0	0	0	0	2012
10437	168	217.1	47588	0	0	0	0	0	0	1	0	0	0	0	0	2012
11197	168	201.3	40633	0	0	0	0	0	0	0	1	0	0	0	0	2012
11388	160	226.6	53652	0	0	0	0	0	0	0	1	0	0	0	0	2012
11726	153	189.3	36646	0	0	0	0	0	0	0	1	0	0	0	1	2012
10989	168	192.4	37036	0	0	0	0	0	0	0	0	1	0	0	0	2012
10773	168	196.9	39175	0	0	0	0	0	0	0	0	1	0	0	0	2012
10638	165	197.6	39630	0	0	0	0	0	0	0	0	1	0	0	0	2012
10787	137	195.7	39790	0	0	0	0	0	0	0	0	1	0	0	1	2012
10961	97	197.0	40584	0	0	0	0	0	0	0	0	0	1	0	1	2012
10768	168	205.7	42661	0	0	0	0	0	0	0	0	0	1	0	0	2012
10790	168	193.7	37770	0	0	0	0	0	0	0	0	0	1	0	0	2012
10857	168	192.7	37305	0	0	0	0	0	0	0	0	0	1	0	0	2012
10775	151	192.8	37303	0	0	0	0	0	0	0	0	0	1	0	0	2012
*11212	85	120.3	14877	0	0	0	0	0	0	0	0	0	0	1	1	2012
11141	104	173.1	30700	0	0	0	0	0	0	0	0	0	0	1	1	2012
11053	168	176.6	32009	0	0	0	0	0	0	0	0	0	0	1	0	2012
10531	168	208.6	44859	0	0	0	0	0	0	0	0	0	0	1	0	2012
10537	168	211.2	46048	0	0	0	0	0	0	0	0	0	0	0	0	2012
10467	168	204.0	42392	0	0	0	0	0	0	0	0	0	0	0	0	2012
10412	142	193.3	37486	0	0	0	0	0	0	0	0	0	0	0	0	2012
11409	125	191.2	37711	0	0	0	1	0	0	0	0	0	0	0	1	2013
11326	168	200.8	40954	0	0	0	1	0	0	0	0	0	0	0	0	2013
11300	168	197.9	39674	0	0	0	1	0	0	0	0	0	0	0	0	2013

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
*10248	19	176.4	33251	0	0	0	0	1	0	0	0	0	0	0	0	2013
11434	165	185.2	35872	0	0	0	0	0	1	0	0	0	0	0	1	2013
11319	117	174.2	31816	0	0	0	0	0	1	0	0	0	0	0	0	2013
13293	32	168.2	31224	0	0	0	0	0	1	0	0	0	0	0	1	2013

HR — Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.

Hour — Number of hours the unit was synchronized during the week.

AMW — Average load on the unit, in MW.

LSRF — Load square range factor, in MW^2.

JAN to NOV — The number 1 indicates the month of the observation. All 0's indicate December.

NS — Number of start ups during the week after being shut down for 24 hours or more.

Year — The year of the observation.

* — Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10698	168	377.3	19457	0	0	0	0	0	0	1	0	0	0	0	0	2010
10768	144	355.8	4404	0	0	0	0	0	0	1	0	0	0	0	1	2010
10701	168	318.8	37546	0	0	0	0	0	0	1	0	0	0	0	0	2010
10832	168	319.1	37271	0	0	0	0	0	0	1	0	0	0	0	0	2010
10454	168	386.5	25717	0	0	0	0	0	0	0	1	0	0	0	0	2010
10422	168	386.2	26634	0	0	0	0	0	0	0	1	0	0	0	0	2010
10586	168	373.6	16086	0	0	0	0	0	0	0	1	0	0	0	0	2010
10699	160	349.7	699	0	0	0	0	0	0	0	1	0	0	0	0	2010
10714	168	353.5	60318	0	0	0	0	0	0	0	1	0	0	0	0	2010
11111	168	368.7	8750	0	0	0	0	0	0	0	0	1	0	0	0	2010
10901	168	403.3	39143	0	0	0	0	0	0	0	0	1	0	0	0	2010
10929	165	375.2	20129	0	0	0	0	0	0	0	0	1	0	0	0	2010
10984	168	328.9	50196	0	0	0	0	0	0	0	0	1	0	0	0	2010
10736	168	304.5	33708	0	0	0	0	0	0	0	0	0	1	0	0	2010
10754	168	295.3	27185	0	0	0	0	0	0	0	0	0	1	0	0	2010
10716	168	282.9	18619	0	0	0	0	0	0	0	0	0	1	0	0	2010
10729	168	297.0	27537	0	0	0	0	0	0	0	0	0	1	0	0	2010
10881	168	277.2	14186	0	0	0	0	0	0	0	0	0	1	0	0	2010
10402	169	332.9	50236	0	0	0	0	0	0	0	0	0	0	1	0	2010
11102	168	257.4	1542	0	0	0	0	0	0	0	0	0	0	1	0	2010
10635	168	367.9	13299	0	0	0	0	0	0	0	0	0	0	1	0	2010
10533	168	376.0	18589	0	0	0	0	0	0	0	0	0	0	1	0	2010
10393	168	420.7	49978	0	0	0	0	0	0	0	0	0	0	0	0	2010
10327	168	436.8	62956	0	0	0	0	0	0	0	0	0	0	0	0	2010
10637	168	391.5	26060	0	0	0	0	0	0	0	0	0	0	0	0	2010
10543	168	416.5	44639	0	0	0	0	0	0	0	0	0	0	0	0	2010
10699	24	395.2	28630	0	0	0	0	0	0	0	0	0	0	0	0	2010
10506	133	368.0	9555	1	0	0	0	0	0	0	0	0	0	0	0	2011
11770	78	276.7	24313	0	1	0	0	0	0	0	0	0	0	0	1	2011
10765	154	379.7	20818	0	1	0	0	0	0	0	0	0	0	0	0	2011
10529	168	392.4	29763	0	1	0	0	0	0	0	0	0	0	0	0	2011
10372	167	392.7	30830	0	0	1	0	0	0	0	0	0	0	0	0	2011
10460	168	389.8	27759	0	0	1	0	0	0	0	0	0	0	0	0	2011
10413	167	387.1	25853	0	0	1	0	0	0	0	0	0	0	0	0	2011
10431	168	411.2	43835	0	0	1	0	0	0	0	0	0	0	0	0	2011
10617	168	417.3	48234	0	0	1	0	0	0	0	0	0	0	0	0	2011
11748	168	382.5	24627	0	0	0	1	0	0	0	0	0	0	0	0	2011
11684	168	388.6	26521	0	0	0	1	0	0	0	0	0	0	0	0	2011
11604	168	401.0	36657	0	0	0	1	0	0	0	0	0	0	0	0	2011
*7665	168	389.6	36657	0	0	0	1	0	0	0	0	0	0	0	0	2011
10737	168	328.1	50084	0	0	0	0	1	0	0	0	0	0	0	0	2011
10919	168	299.5	30837	0	0	0	0	1	0	0	0	0	0	0	0	2011
11161	168	276.4	14670	0	0	0	0	1	0	0	0	0	0	0	0	2011
10966	168	343.5	62084	0	0	0	0	1	0	0	0	0	0	0	0	2011
10521	107	364.8	15516	0	0	0	0	1	0	0	0	0	0	0	1	2011
10883	168	371.2	16958	0	0	0	0	0	1	0	0	0	0	0	0	2011
11000	168	358.5	7445	0	0	0	0	0	1	0	0	0	0	0	0	2011

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11064	168	352.9	3984	0	0	0	0	0	1	0	0	0	0	0	0	2011
11109	123	343.5	62841	0	0	0	0	0	1	0	0	0	0	0	0	2011
10391	168	365.2	12555	0	0	0	0	0	0	1	0	0	0	0	0	2011
10459	168	383.7	25816	0	0	0	0	0	0	1	0	0	0	0	0	2011
10596	168	340.9	59287	0	0	0	0	0	0	1	0	0	0	0	0	2011
10622	168	352.8	2580	0	0	0	0	0	0	1	0	0	0	0	0	2011
10619	168	377.3	19317	0	0	0	0	0	0	0	1	0	0	0	0	2011
10960	168	364.3	10832	0	0	0	0	0	0	0	1	0	0	0	0	2011
11118	166	308.7	43716	0	0	0	0	0	0	0	1	0	0	0	0	2011
10895	168	368.6	14375	0	0	0	0	0	0	0	1	0	0	0	0	2011
11046	115	342.8	63916	0	0	0	0	0	0	0	1	0	0	0	0	2011
11031	163	297.7	30265	0	0	0	0	0	0	0	0	1	0	0	1	2011
10697	168	336.9	57109	0	0	0	0	0	0	0	0	1	0	0	0	2011
10564	168	349.3	123	0	0	0	0	0	0	0	0	1	0	0	0	2011
10325	168	385.6	23743	0	0	0	0	0	0	0	0	1	0	0	0	2011
10380	168	345.8	56379	0	0	0	0	0	0	0	0	0	1	0	0	2011
10762	168	337.8	52893	0	0	0	0	0	0	0	0	0	1	0	0	2011
10628	168	335.2	51542	0	0	0	0	0	0	0	0	0	1	0	0	2011
10766	168	310.6	33476	0	0	0	0	0	0	0	0	0	1	0	0	2011
10886	168	309.0	31153	0	0	0	0	0	0	0	0	0	1	0	0	2011
10913	169	299.8	25404	0	0	0	0	0	0	0	0	0	0	1	0	2011
10904	168	312.8	34397	0	0	0	0	0	0	0	0	0	0	1	0	2011
11124	168	296.3	22885	0	0	0	0	0	0	0	0	0	0	1	0	2011
10828	168	318.3	39330	0	0	0	0	0	0	0	0	0	0	1	0	2011
10973	168	324.0	42862	0	0	0	0	0	0	0	0	0	0	0	0	2011
10825	49	343.2	57591	0	0	0	0	0	0	0	0	0	0	0	0	2011
11562	109	252.5	1270	1	0	0	0	0	0	0	0	0	0	0	1	2012
11363	168	257.7	1423	1	0	0	0	0	0	0	0	0	0	0	0	2012
11325	168	263.0	4737	1	0	0	0	0	0	0	0	0	0	0	0	2012
11742	119	251.1	65202	1	0	0	0	0	0	0	0	0	0	0	1	2012
11276	168	253.1	64136	0	1	0	0	0	0	0	0	0	0	0	0	2012
11438	168	260.1	3349	0	1	0	0	0	0	0	0	0	0	0	0	2012
11410	168	264.9	6768	0	1	0	0	0	0	0	0	0	0	0	0	2012
11488	168	251.7	63397	0	1	0	0	0	0	0	0	0	0	0	0	2012
11957	168	248.9	61984	0	1	0	0	0	0	0	0	0	0	0	0	2012
*12412	168	248.9	61984	0	1	0	0	0	0	0	0	0	0	0	0	2012
11830	167	252.2	63729	0	0	1	0	0	0	0	0	0	0	0	0	2012
10377	168	271.1	10881	0	0	1	0	0	0	0	0	0	0	0	0	2012
10308	168	253.3	64299	0	0	1	0	0	0	0	0	0	0	0	0	2012
11664	161	251.8	65330	0	0	0	1	0	0	0	0	0	0	0	0	2012
11435	168	250.0	62674	0	0	0	1	0	0	0	0	0	0	0	0	2012
11574	168	264.0	6937	0	0	0	1	0	0	0	0	0	0	0	0	2012
11942	167	266.3	8987	0	0	0	1	0	0	0	0	0	0	0	0	2012
12131	133	257.4	2873	0	0	0	0	1	0	0	0	0	0	0	1	2012
12302	96	271.3	13039	0	0	0	0	1	0	0	0	0	0	0	0	2012
11943	147	290.3	26198	0	0	0	0	1	0	0	0	0	0	0	1	2012
11814	139	280.9	17887	0	0	0	0	1	0	0	0	0	0	0	0	2012

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10999	143	289.2	24967	0	0	0	0	0	1	0	0	0	0	0	1	2012
11259	168	257.3	1201	0	0	0	0	0	1	0	0	0	0	0	0	2012
11159	168	285.7	21518	0	0	0	0	0	1	0	0	0	0	0	0	2012
10837	168	291.2	23172	0	0	0	0	0	1	0	0	0	0	0	0	2012
11257	168	285.5	20087	0	0	0	0	0	0	1	0	0	0	0	0	2012
11380	168	267.3	8682	0	0	0	0	0	0	1	0	0	0	0	0	2012
11382	146	267.9	8544	0	0	0	0	0	0	1	0	0	0	0	0	2012
11531	145	269.6	15252	0	0	0	0	0	0	1	0	0	0	0	1	2012
10852	168	275.9	13788	0	0	0	0	0	0	0	1	0	0	0	0	2012
10173	165	294.1	27953	0	0	0	0	0	0	0	1	0	0	0	0	2012
11021	168	263.3	5637	0	0	0	0	0	0	0	1	0	0	0	0	2012
12054	168	250.9	63309	0	0	0	0	0	0	0	1	0	0	0	0	2012
10464	100	268.2	9912	0	0	0	0	0	0	0	1	0	0	0	0	2012
*13729	100	268.2	6017	0	0	0	0	0	0	0	1	0	0	0	0	2012
10981	168	265.9	8395	0	0	0	0	0	0	0	0	0	0	0	0	2012
*12871	168	265.9	71849	0	0	0	0	0	0	0	0	0	0	0	0	2012
11066	168	261.0	4907	1	0	0	0	0	0	0	0	0	0	0	0	2013
10829	163	280.8	18001	1	0	0	0	0	0	0	0	0	0	0	0	2013
10860	168	280.8	18584	1	0	0	0	0	0	0	0	0	0	0	0	2013
10729	168	266.7	8116	1	0	0	0	0	0	0	0	0	0	0	0	2013
11046	168	248.1	61794	0	1	0	0	0	0	0	0	0	0	0	0	2013
11434	168	247.2	61146	0	1	0	0	0	0	0	0	0	0	0	0	2013
11335	168	254.6	65469	0	1	0	0	0	0	0	0	0	0	0	0	2013
11239	168	250.1	62578	0	1	0	0	0	0	0	0	0	0	0	0	2013
10821	168	249.0	62111	0	0	1	0	0	0	0	0	0	0	0	0	2013
10640	167	247.1	61080	0	0	1	0	0	0	0	0	0	0	0	0	2013
10783	168	254.2	65281	0	0	1	0	0	0	0	0	0	0	0	0	2013
10683	158	249.7	63426	0	0	1	0	0	0	0	0	0	0	0	0	2013
10602	168	258.4	2338	0	0	1	0	0	0	0	0	0	0	0	0	2013
10847	168	259.7	2815	0	0	0	1	0	0	0	0	0	0	0	0	2013
10946	61	255.8	1734	0	0	0	1	0	0	0	0	0	0	0	0	2013
11356	157	249.1	62769	0	0	0	0	1	0	0	0	0	0	0	1	2013
10664	168	255.4	444	0	0	0	0	1	0	0	0	0	0	0	0	2013
10610	168	258.1	1774	0	0	0	0	1	0	0	0	0	0	0	0	2013
10640	168	266.8	6949	0	0	0	0	1	0	0	0	0	0	0	0	2013
10647	168	272.9	11037	0	0	0	0	1	0	0	0	0	0	0	0	2013
10812	168	254.3	65164	0	0	0	0	0	1	0	0	0	0	0	0	2013
10508	168	295.9	27677	0	0	0	0	0	1	0	0	0	0	0	0	2013
11057	168	259.7	5141	0	0	0	0	0	1	0	0	0	0	0	0	2013
10858	144	292.4	25400	0	0	0	0	0	1	0	0	0	0	0	0	2013
10858	144	292.4	25400	0	0	0	0	0	1	0	0	0	0	0	0	2013

Data Base for CRIST 7 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hour	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
Year	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10664	144	126.6	17498	0	0	0	0	0	1	0	0	0	0	0	0	2010
10479	168	123.0	16748	0	0	0	0	0	0	1	0	0	0	0	0	2010
10697	168	126.6	17641	0	0	0	0	0	0	1	0	0	0	0	0	2010
10590	167	121.8	16550	0	0	0	0	0	0	1	0	0	0	0	0	2010
10589	168	126.7	17578	0	0	0	0	0	0	1	0	0	0	0	0	2010
10565	168	128.6	18074	0	0	0	0	0	0	0	1	0	0	0	0	2010
10498	168	125.0	17303	0	0	0	0	0	0	0	1	0	0	0	0	2010
10487	168	127.4	17841	0	0	0	0	0	0	0	1	0	0	0	0	2010
10639	140	120.7	16350	0	0	0	0	0	0	0	1	0	0	0	1	2010
10465	168	127.2	17518	0	0	0	0	0	0	0	1	0	0	0	0	2010
10460	168	123.4	16819	0	0	0	0	0	0	0	0	1	0	0	0	2010
10423	168	129.2	18259	0	0	0	0	0	0	0	0	1	0	0	0	2010
10415	168	127.7	17899	0	0	0	0	0	0	0	0	1	0	0	0	2010
10720	168	94.9	10299	0	0	0	0	0	0	0	0	1	0	0	0	2010
11008	168	75.6	5995	0	0	0	0	0	0	0	0	0	1	0	0	2010
10852	168	81.4	7271	0	0	0	0	0	0	0	0	0	1	0	0	2010
11048	168	76.2	6181	0	0	0	0	0	0	0	0	0	1	0	0	2010
10945	168	83.5	7668	0	0	0	0	0	0	0	0	0	1	0	0	2010
11233	168	71.4	5254	0	0	0	0	0	0	0	0	0	1	0	0	2010
10973	112	87.5	8728	0	0	0	0	0	0	0	0	0	0	1	1	2010
10437	168	115.5	13690	0	0	0	0	0	0	0	0	0	0	1	0	2010
10438	168	135.0	19069	0	0	0	0	0	0	0	0	0	0	1	0	2010
10558	168	127.7	17357	0	0	0	0	0	0	0	0	0	0	1	0	2010
10330	168	144.0	21271	0	0	0	0	0	0	0	0	0	0	0	0	2010
10327	168	150.0	22771	0	0	0	0	0	0	0	0	0	0	0	0	2010
10394	168	139.2	20243	0	0	0	0	0	0	0	0	0	0	0	0	2010
10407	168	146.7	21924	0	0	0	0	0	0	0	0	0	0	0	0	2010
10466	24	144.3	21258	0	0	0	0	0	0	0	0	0	0	0	0	2010
10513	168	135.1	19204	1	0	0	0	0	0	0	0	0	0	0	0	2011
10468	168	144.4	21285	1	0	0	0	0	0	0	0	0	0	0	0	2011
10337	71	138.0	19985	1	0	0	0	0	0	0	0	0	0	0	0	2011
10803	119	98.1	9916	0	1	0	0	0	0	0	0	0	0	0	1	2011
10634	168	97.6	10065	0	1	0	0	0	0	0	0	0	0	0	0	2011
10641	168	111.2	13806	0	1	0	0	0	0	0	0	0	0	0	0	2011
10677	168	101.4	11646	0	0	1	0	0	0	0	0	0	0	0	0	2011
11226	72	124.5	17375	0	0	1	0	0	0	0	0	0	0	0	3	2011
10496	168	133.4	19024	0	0	0	1	0	0	0	0	0	0	0	0	2011
10618	51	124.8	17246	0	0	0	1	0	0	0	0	0	0	0	1	2011
10304	168	128.1	17618	0	0	0	1	0	0	0	0	0	0	0	0	2011
10817	168	92.9	9669	0	0	0	0	1	0	0	0	0	0	0	0	2011
11070	168	78.8	6578	0	0	0	0	1	0	0	0	0	0	0	0	2011
11064	168	78.9	6830	0	0	0	0	1	0	0	0	0	0	0	0	2011
11059	168	78.3	6442	0	0	0	0	1	0	0	0	0	0	0	0	2011
10801	168	87.6	8323	0	0	0	0	1	0	0	0	0	0	0	0	2011
10880	141	82.4	7325	0	0	0	0	0	1	0	0	0	0	0	1	2011
10799	168	91.1	9324	0	0	0	0	0	1	0	0	0	0	0	0	2011
10955	168	79.4	6685	0	0	0	0	0	1	0	0	0	0	0	0	2011

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11088	144	76.2	5984	0	0	0	0	0	1	0	0	0	0	0	0	2011
10848	168	85.8	8026	0	0	0	0	0	0	1	0	0	0	0	0	2011
10881	168	86.3	8015	0	0	0	0	0	0	1	0	0	0	0	0	2011
10998	168	81.0	7029	0	0	0	0	0	0	1	0	0	0	0	0	2011
10988	168	83.3	7483	0	0	0	0	0	0	1	0	0	0	0	0	2011
10787	168	90.0	8873	0	0	0	0	0	0	0	1	0	0	0	0	2011
10991	168	84.7	7780	0	0	0	0	0	0	0	1	0	0	0	0	2011
11012	168	83.8	7512	0	0	0	0	0	0	0	1	0	0	0	0	2011
10892	168	86.4	8057	0	0	0	0	0	0	0	1	0	0	0	0	2011
10789	168	85.6	7928	0	0	0	0	0	0	0	1	0	0	0	0	2011
11045	145	75.6	6065	0	0	0	0	0	0	0	0	1	0	0	0	2011
11014	165	71.5	5167	0	0	0	0	0	0	0	0	0	1	0	1	2011
10652	169	70.9	5033	0	0	0	0	0	0	0	0	0	0	1	0	2011
10642	168	70.2	4929	0	0	0	0	0	0	0	0	0	0	1	0	2011
10608	168	72.3	5292	0	0	0	0	0	0	0	0	0	0	1	0	2011
10769	168	73.7	5472	0	0	0	0	0	0	0	0	0	0	1	0	2011
10758	168	74.6	5716	0	0	0	0	0	0	0	0	0	0	0	0	2011
10763	168	76.0	5923	0	0	0	0	0	0	0	0	0	0	0	0	2011
10678	168	70.3	4944	0	0	0	0	0	0	0	0	0	0	0	0	2011
10605	24	69.5	4836	0	0	0	0	0	0	0	0	0	0	0	0	2011
10758	168	75.8	5965	1	0	0	0	0	0	0	0	0	0	0	0	2012
10881	168	73.9	5516	1	0	0	0	0	0	0	0	0	0	0	0	2012
10693	168	72.5	5329	1	0	0	0	0	0	0	0	0	0	0	0	2012
10772	168	70.1	4931	1	0	0	0	0	0	0	0	0	0	0	0	2012
10797	168	70.1	4918	0	1	0	0	0	0	0	0	0	0	0	0	2012
10702	168	74.5	5758	0	1	0	0	0	0	0	0	0	0	0	0	2012
10634	168	77.4	6252	0	1	0	0	0	0	0	0	0	0	0	0	2012
10923	168	70.8	5020	0	1	0	0	0	0	0	0	0	0	0	0	2012
10774	168	69.9	4896	0	1	0	0	0	0	0	0	0	0	0	0	2012
10704	168	69.5	4833	0	0	1	0	0	0	0	0	0	0	0	0	2012
10633	167	71.3	5202	0	0	1	0	0	0	0	0	0	0	0	0	2012
10809	163	70.1	4956	0	0	1	0	0	0	0	0	0	0	0	0	2012
10823	168	70.0	4909	0	0	1	0	0	0	0	0	0	0	0	0	2012
10829	168	69.6	4849	0	0	0	1	0	0	0	0	0	0	0	0	2012
10816	120	69.4	4833	0	0	0	1	0	0	0	0	0	0	0	0	2012
11133	59	70.8	5556	0	0	0	1	0	0	0	0	0	0	0	1	2012
10514	167	84.6	8252	0	0	0	1	0	0	0	0	0	0	0	0	2012
10581	168	76.4	6171	0	0	0	0	1	0	0	0	0	0	0	0	2012
10594	167	69.8	4883	0	0	0	0	1	0	0	0	0	0	0	0	2012
11116	24	99.8	11365	0	0	0	0	1	0	0	0	0	0	0	1	2012
10682	168	76.9	6319	0	0	0	0	1	0	0	0	0	0	0	0	2012
10743	168	69.4	4820	0	0	0	0	0	1	0	0	0	0	0	0	2012
10725	168	71.6	5202	0	0	0	0	0	1	0	0	0	0	0	0	2012
10920	168	71.1	5167	0	0	0	0	0	1	0	0	0	0	0	0	2012
10601	168	78.9	6605	0	0	0	0	0	1	0	0	0	0	0	0	2012
10766	168	87.0	8534	0	0	0	0	0	0	1	0	0	0	0	0	2012
10627	168	77.7	6511	0	0	0	0	0	0	1	0	0	0	0	0	2012

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11025	168	74.8	5755	0	0	0	0	0	0	1	0	0	0	0	0	2012
10750	168	85.0	7898	0	0	0	0	0	0	1	0	0	0	0	0	2012
11128	132	78.8	6769	0	0	0	0	0	0	0	1	0	0	0	1	2012
11004	168	69.7	4867	0	0	0	0	0	0	0	1	0	0	0	0	2012
10873	168	71.1	5101	0	0	0	0	0	0	0	1	0	0	0	0	2012
11127	168	70.2	4944	0	0	0	0	0	0	0	1	0	0	0	0	2012
11140	168	71.3	5208	0	0	0	0	0	0	0	1	0	0	0	0	2012
11188	168	71.4	5191	0	0	0	0	0	0	0	0	1	0	0	0	2012
10814	100	77.7	6728	0	0	0	0	0	0	0	0	1	0	0	0	2012
11218	121	71.0	5227	0	0	0	0	0	0	0	0	0	0	1	2	2012
10731	168	70.2	4929	0	0	0	0	0	0	0	0	0	0	1	0	2012
10750	168	75.0	5771	0	0	0	0	0	0	0	0	0	0	1	0	2012
10763	168	71.4	5162	0	0	0	0	0	0	0	0	0	0	0	0	2012
10837	168	73.6	5450	0	0	0	0	0	0	0	0	0	0	0	0	2012
11223	168	74.1	5587	0	0	0	0	0	0	0	0	0	0	0	0	2012
10738	168	81.6	6796	0	0	0	0	0	0	0	0	0	0	0	0	2012
10052	24	95.1	9110	0	0	0	0	0	0	0	0	0	0	0	0	2012
10894	168	78.1	6164	1	0	0	0	0	0	0	0	0	0	0	0	2013
11060	168	70.6	5043	1	0	0	0	0	0	0	0	0	0	0	0	2013
11027	168	73.7	5474	1	0	0	0	0	0	0	0	0	0	0	0	2013
10912	168	71.5	5168	1	0	0	0	0	0	0	0	0	0	0	0	2013
10867	168	71.6	5192	0	1	0	0	0	0	0	0	0	0	0	0	2013
11035	168	70.9	5094	0	1	0	0	0	0	0	0	0	0	0	0	2013
10998	168	72.7	5387	0	1	0	0	0	0	0	0	0	0	0	0	2013
11166	168	76.6	6083	0	1	0	0	0	0	0	0	0	0	0	0	2013
11188	168	79.2	6392	0	0	1	0	0	0	0	0	0	0	0	0	2013
11150	167	74.7	5742	0	0	1	0	0	0	0	0	0	0	0	0	2013
10863	168	74.4	5700	0	0	1	0	0	0	0	0	0	0	0	0	2013
10935	168	88.7	9008	0	0	1	0	0	0	0	0	0	0	0	0	2013
10777	168	87.0	8487	0	0	1	0	0	0	0	0	0	0	0	0	2013
10992	168	75.4	5813	0	0	0	1	0	0	0	0	0	0	0	0	2013
10948	97	74.8	5807	0	0	0	1	0	0	0	0	0	0	0	0	2013
11003	168	72.7	5479	0	0	0	1	0	0	0	0	0	0	0	0	2013
10817	168	74.2	5658	0	0	0	0	1	0	0	0	0	0	0	0	2013
10917	168	73.4	5606	0	0	0	0	1	0	0	0	0	0	0	0	2013
10835	168	75.1	5908	0	0	0	0	1	0	0	0	0	0	0	0	2013
10862	168	78.1	6406	0	0	0	0	1	0	0	0	0	0	0	0	2013
10785	168	92.7	9689	0	0	0	0	1	0	0	0	0	0	0	0	2013
10943	168	75.6	5938	0	0	0	0	0	1	0	0	0	0	0	0	2013
10806	168	101.0	11652	0	0	0	0	0	1	0	0	0	0	0	0	2013
10918	168	84.4	7869	0	0	0	0	0	1	0	0	0	0	0	0	2013
10801	144	94.8	10236	0	0	0	0	0	1	0	0	0	0	0	0	2013

Data Base for SMITH 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.
Hour	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of start ups during the week after being shut down for 24 hours or more.
Year	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10643	168	138.1	21740	0	0	0	0	0	0	1	0	0	0	0	0	2010
10737	168	144.7	23609	0	0	0	0	0	0	1	0	0	0	0	0	2010
10604	168	141.1	22587	0	0	0	0	0	0	1	0	0	0	0	0	2010
10598	168	147.0	24206	0	0	0	0	0	0	1	0	0	0	0	0	2010
10596	168	146.5	24125	0	0	0	0	0	0	0	1	0	0	0	0	2010
10589	168	142.8	23277	0	0	0	0	0	0	0	1	0	0	0	0	2010
10629	168	144.8	23718	0	0	0	0	0	0	0	1	0	0	0	0	2010
10582	168	143.6	23295	0	0	0	0	0	0	0	1	0	0	0	0	2010
10607	168	145.9	23732	0	0	0	0	0	0	0	1	0	0	0	0	2010
10582	168	138.9	22140	0	0	0	0	0	0	0	0	1	0	0	0	2010
10554	168	147.0	24255	0	0	0	0	0	0	0	0	1	0	0	0	2010
10685	168	145.7	23857	0	0	0	0	0	0	0	0	1	0	0	0	2010
10742	76	130.7	19458	0	0	0	0	0	0	0	0	1	0	0	0	2010
*16436	01	14.0	196	0	0	0	0	0	0	0	0	1	0	0	0	2010
10755	169	105.8	13010	0	0	0	0	0	0	0	0	0	0	1	0	2010
10542	168	160.6	27116	0	0	0	0	0	0	0	0	0	0	1	0	2010
10436	49	149.8	24712	0	0	0	0	0	0	0	0	0	0	1	0	2010
11147	46	121.7	15446	0	0	0	0	0	0	0	0	0	0	0	1	2010
10628	137	127.3	16832	0	0	0	0	0	0	0	0	0	0	0	0	2010
10664	125	122.1	15660	1	0	0	0	0	0	0	0	0	0	0	1	2011
10311	168	135.2	20078	1	0	0	0	0	0	0	0	0	0	0	0	2011
10636	168	174.9	31220	1	0	0	0	0	0	0	0	0	0	0	0	2011
10561	168	166.5	28823	0	1	0	0	0	0	0	0	0	0	0	0	2011
10584	168	172.0	30189	0	1	0	0	0	0	0	0	0	0	0	0	2011
10528	168	152.0	24656	0	1	0	0	0	0	0	0	0	0	0	0	2011
10808	168	106.8	13736	0	1	0	0	0	0	0	0	0	0	0	0	2011
10512	95	155.4	26132	0	0	1	0	0	0	0	0	0	0	0	0	2011
10423	70	129.3	19383	0	0	1	0	0	0	0	0	0	0	0	1	2011
10313	168	153.7	25329	0	0	1	0	0	0	0	0	0	0	0	0	2011
10430	95	160.4	27178	0	0	1	0	0	0	0	0	0	0	0	0	2011
10545	128	159.9	27355	0	0	0	1	0	0	0	0	0	0	0	1	2011
11084	4	68.5	6434	0	0	0	1	0	0	0	0	0	0	0	0	2011
11188	77	88.3	8244	0	0	0	0	1	0	0	0	0	0	0	1	2011
11130	39	74.4	5878	0	0	0	0	1	0	0	0	0	0	0	0	2011
11322	112	80.8	6931	0	0	0	0	1	0	0	0	0	0	0	1	2011
10940	168	99.1	11263	0	0	0	0	1	0	0	0	0	0	0	0	2011
10901	168	93.8	9907	0	0	0	0	0	1	0	0	0	0	0	0	2011
11158	168	100.5	12019	0	0	0	0	0	1	0	0	0	0	0	0	2011
11043	168	86.6	8433	0	0	0	0	0	1	0	0	0	0	0	0	2011
11352	144	82.1	7233	0	0	0	0	0	1	0	0	0	0	0	0	2011
11181	168	95.4	10568	0	0	0	0	0	0	1	0	0	0	0	0	2011
10989	168	97.9	10868	0	0	0	0	0	0	1	0	0	0	0	0	2011
11263	168	87.5	8567	0	0	0	0	0	0	1	0	0	0	0	0	2011
11288	168	89.1	8911	0	0	0	0	0	0	1	0	0	0	0	0	2011
11076	168	102.0	11971	0	0	0	0	0	0	0	1	0	0	0	0	2011
11146	168	95.2	10411	0	0	0	0	0	0	0	1	0	0	0	0	2011
10943	168	94.0	10077	0	0	0	0	0	0	0	1	0	0	0	0	2011

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10952	168	98.7	11133	0	0	0	0	0	0	0	1	0	0	0	0	2011
10953	168	96.4	10654	0	0	0	0	0	0	0	1	0	0	0	0	2011
11435	168	70.6	5044	0	0	0	0	0	0	0	0	1	0	0	0	2011
10958	168	87.8	8745	0	0	0	0	0	0	0	0	1	0	0	0	2011
10950	168	81.9	7384	0	0	0	0	0	0	0	0	1	0	0	0	2011
10905	168	92.9	10029	0	0	0	0	0	0	0	0	1	0	0	0	2011
11092	168	70.7	5053	0	0	0	0	0	0	0	0	0	1	0	0	2011
10932	168	81.0	7042	0	0	0	0	0	0	0	0	0	1	0	0	2011
11118	168	73.1	5575	0	0	0	0	0	0	0	0	0	1	0	0	2011
11201	168	74.6	6008	0	0	0	0	0	0	0	0	0	1	0	0	2011
10941	19	116.4	15437	0	0	0	0	0	0	0	0	0	1	0	0	2011
10811	152	85.2	7648	0	0	0	0	0	0	0	0	0	0	0	1	2011
10595	101	88.7	8720	0	0	0	0	0	0	0	0	0	0	0	0	2011
10978	106	75.6	6162	0	0	0	1	0	0	0	0	0	0	0	1	2012
10521	168	70.9	5101	0	0	0	1	0	0	0	0	0	0	0	0	2012
10304	168	91.5	10209	0	0	0	1	0	0	0	0	0	0	0	0	2012
10513	168	75.2	6003	0	0	0	0	1	0	0	0	0	0	0	0	2012
10550	168	76.4	6530	0	0	0	0	1	0	0	0	0	0	0	0	2012
10855	168	73.6	5663	0	0	0	0	1	0	0	0	0	0	0	0	2012
11009	168	76.9	6433	0	0	0	0	1	0	0	0	0	0	0	0	2012
10432	29	139.7	22697	0	0	0	0	1	0	0	0	0	0	0	0	2012
11204	116	87.0	9121	0	0	0	0	0	0	1	0	0	0	0	1	2012
11139	168	78.7	6996	0	0	0	0	0	0	1	0	0	0	0	0	2012
11360	168	72.5	5405	0	0	0	0	0	0	1	0	0	0	0	0	2012
11111	168	84.9	8288	0	0	0	0	0	0	1	0	0	0	0	0	2012
11310	168	74.0	5851	0	0	0	0	0	0	0	1	0	0	0	0	2012
11452	168	68.8	4729	0	0	0	0	0	0	0	1	0	0	0	0	2012
11389	168	70.2	5014	0	0	0	0	0	0	0	1	0	0	0	0	2012
11338	168	69.3	4806	0	0	0	0	0	0	0	1	0	0	0	0	2012
11708	168	71.1	5101	0	0	0	0	0	0	0	1	0	0	0	0	2012
11434	168	80.2	6825	0	0	0	0	0	0	0	0	1	0	0	0	2012
11493	168	66.9	4497	0	0	0	0	0	0	0	0	1	0	0	0	2012
11481	168	69.7	4931	0	0	0	0	0	0	0	0	1	0	0	0	2012
11416	168	70.3	5044	0	0	0	0	0	0	0	0	1	0	0	0	2012
11400	168	70.0	4931	0	0	0	0	0	0	0	0	0	1	0	0	2012
11326	168	70.1	4995	0	0	0	0	0	0	0	0	0	1	0	0	2012
11277	168	71.7	5325	0	0	0	0	0	0	0	0	0	1	0	0	2012
11081	168	71.5	5270	0	0	0	0	0	0	0	0	0	1	0	0	2012
10979	168	71.6	5237	0	0	0	0	0	0	0	0	0	1	0	0	2012
11021	169	72.0	5311	0	0	0	0	0	0	0	0	0	0	1	0	2012
11064	168	69.6	4855	0	0	0	0	0	0	0	0	0	0	1	0	2012
10676	60	88.6	8632	0	0	0	0	0	0	0	0	0	0	1	0	2012
11632	9	85.6	8296	0	0	1	0	0	0	0	0	0	0	0	1	2013
10795	168	88.7	9260	0	0	1	0	0	0	0	0	0	0	0	0	2013
10938	168	89.7	9180	0	0	1	0	0	0	0	0	0	0	0	0	2013
11043	168	72.2	5303	0	0	0	1	0	0	0	0	0	0	0	0	2013
11202	168	71.8	5350	0	0	0	1	0	0	0	0	0	0	0	0	2013

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10911	168	86.8	8639	0	0	0	1	0	0	0	0	0	0	0	0	2013
12001	35	72.8	5989	0	0	0	0	0	1	0	0	0	0	0	2	2013
10986	168	86.3	8900	0	0	0	0	0	1	0	0	0	0	0	0	2013
11124	168	78.4	7098	0	0	0	0	0	1	0	0	0	0	0	0	2013
11096	144	81.1	7618	0	0	0	0	0	1	0	0	0	0	0	0	2013
11096	144	81.1	7618	0	0	0	0	0	1	0	0	0	0	0	0	2013

HR — Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.

Hour — Number of hours the unit was synchronized during the week.

AMW — Average load on the unit, in MW.

LSRF — Load square range factor, in MW^2.

JAN to NOV — The number 1 indicates the month of the observation. All 0's indicate December.

NS — Number of start ups during the week after being shut down for 24 hours or more.

Year — The year of the observation.

* — Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 3 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
6994	129	424.1	3712408	0	0	0	0	0	0	1	0	0	0	0	0	2010
7009	151	455.1	4804893	0	0	0	0	0	0	1	0	0	0	0	0	2010
6880	160	453.7	4979844	0	0	0	0	0	0	1	0	0	0	0	0	2010
7002	167	413.2	4529694	0	0	0	0	0	0	1	0	0	0	0	0	2010
7014	162	460.3	5113525	0	0	0	0	0	0	0	1	0	0	0	0	2010
7035	166	470.4	5439111	0	0	0	0	0	0	0	1	0	0	0	0	2010
*9010	118	346.7	2712508	0	0	0	0	0	0	0	1	0	0	0	2	2010
6945	168	475.6	5547789	0	0	0	0	0	0	0	1	0	0	0	0	2010
6786	161	457.9	4997876	0	0	0	0	0	0	0	1	0	0	0	0	2010
6934	146	460.2	4671376	0	0	0	0	0	0	0	0	1	0	0	0	2010
6961	168	412.4	4547125	0	0	0	0	0	0	0	0	1	0	0	0	2010
6988	168	406.9	4507612	0	0	0	0	0	0	0	0	1	0	0	0	2010
6822	153	419.4	4210303	0	0	0	0	0	0	0	0	1	0	0	0	2010
6715	168	403.1	4339752	0	0	0	0	0	0	0	0	0	1	0	0	2010
6781	168	443.0	5093443	0	0	0	0	0	0	0	0	0	1	0	0	2010
6865	168	453.1	5238446	0	0	0	0	0	0	0	0	0	1	0	0	2010
6881	168	442.8	5057711	0	0	0	0	0	0	0	0	0	1	0	0	2010
6672	168	494.4	5992759	0	0	0	0	0	0	0	0	0	1	0	0	2010
6843	145	483.4	5140044	0	0	0	0	0	0	0	0	0	0	1	0	2010
7378	22	395.5	646722	0	0	0	0	0	0	0	0	0	0	1	1	2010
6921	164	430.3	4566004	0	0	0	0	0	0	0	0	0	0	1	0	2010
6903	168	407.2	4369617	0	0	0	0	0	0	0	0	0	0	1	0	2010
6846	168	519.2	6621616	0	0	0	0	0	0	0	0	0	0	0	0	2010
6850	168	492.1	5994320	0	0	0	0	0	0	0	0	0	0	0	0	2010
6923	168	459.5	5207200	0	0	0	0	0	0	0	0	0	0	0	0	2010
6996	168	523.0	6707733	0	0	0	0	0	0	0	0	0	0	0	0	2010
6889	168	440.7	4998604	1	0	0	0	0	0	0	0	0	0	0	0	2011
6793	168	526.2	6785539	1	0	0	0	0	0	0	0	0	0	0	0	2011
6827	168	496.0	6031649	1	0	0	0	0	0	0	0	0	0	0	0	2011
6935	168	520.5	6607604	1	0	0	0	0	0	0	0	0	0	0	0	2011
6840	168	447.0	5197016	0	1	0	0	0	0	0	0	0	0	0	0	2011
6837	168	515.4	6496114	0	1	0	0	0	0	0	0	0	0	0	0	2011
6878	168	455.5	5127500	0	1	0	0	0	0	0	0	0	0	0	0	2011
*7894	86	414.4	2382352	0	0	1	0	0	0	0	0	0	0	0	0	2011
6786	168	477.0	5753988	0	0	1	0	0	0	0	0	0	0	0	0	2011
6892	167	411.1	4354156	0	0	1	0	0	0	0	0	0	0	0	0	2011
6860	168	426.1	4784770	0	0	1	0	0	0	0	0	0	0	0	0	2011
6666	168	420.7	4596707	0	0	1	0	0	0	0	0	0	0	0	0	2011
6887	168	411.5	4346557	0	0	0	1	0	0	0	0	0	0	0	0	2011
7027	168	404.4	4170481	0	0	0	1	0	0	0	0	0	0	0	0	2011
7047	168	346.1	3192466	0	0	0	1	0	0	0	0	0	0	0	0	2011
6698	168	344.0	3337623	0	0	0	1	0	0	0	0	0	0	0	0	2011
6781	168	450.8	5219671	0	0	0	0	1	0	0	0	0	0	0	0	2011
6777	168	430.4	4748692	0	0	0	0	1	0	0	0	0	0	0	0	2011
7079	129	367.7	2867719	0	0	0	0	1	0	0	0	0	0	0	1	2011
6792	168	419.3	4699875	0	0	0	0	1	0	0	0	0	0	0	0	2011
6817	168	450.5	5243165	0	0	0	0	1	0	0	0	0	0	0	0	2011

Data Base for SMITH 3 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
6942	168	457.8	5327195	0	0	0	0	0	1	0	0	0	0	0	0	2011
6894	168	429.1	4754014	0	0	0	0	0	1	0	0	0	0	0	0	2011
6860	168	450.5	5161119	0	0	0	0	0	1	0	0	0	0	0	0	2011
6778	144	433.0	4853013	0	0	0	0	0	1	0	0	0	0	0	0	2011
6945	168	444.4	5048187	0	0	0	0	0	0	1	0	0	0	0	0	2011
6837	168	499.0	6026769	0	0	0	0	0	0	1	0	0	0	0	0	2011
6857	168	459.4	5259554	0	0	0	0	0	0	1	0	0	0	0	0	2011
6811	168	485.5	5750907	0	0	0	0	0	0	1	0	0	0	0	0	2011
6865	168	492.4	5894218	0	0	0	0	0	0	0	1	0	0	0	0	2011
7008	168	465.0	5320635	0	0	0	0	0	0	0	1	0	0	0	0	2011
6918	168	469.7	5427225	0	0	0	0	0	0	0	1	0	0	0	0	2011
6871	168	490.7	5427225	0	0	0	0	0	0	0	1	0	0	0	0	2011
6895	168	466.4	5441192	0	0	0	0	0	0	0	1	0	0	0	0	2011
6926	168	430.1	4742897	0	0	0	0	0	0	0	0	1	0	0	0	2011
6915	168	437.7	4962962	0	0	0	0	0	0	0	0	1	0	0	0	2011
6814	168	451.8	5225634	0	0	0	0	0	0	0	0	1	0	0	0	2011
6769	168	500.4	6067034	0	0	0	0	0	0	0	0	1	0	0	0	2011
6766	168	475.5	5527666	0	0	0	0	0	0	0	0	0	1	0	0	2011
6933	168	445.8	5222503	0	0	0	0	0	0	0	0	0	1	0	0	2011
6758	168	497.0	6070664	0	0	0	0	0	0	0	0	0	1	0	0	2011
6532	168	506.1	6205182	0	0	0	0	0	0	0	0	0	1	0	0	2011
6631	168	548.4	7244548	0	0	0	0	0	0	0	0	0	1	0	0	2011
6850	154	522.9	6159788	0	0	0	0	0	0	0	0	0	0	1	0	2011
6845	168	500.0	6267007	0	0	0	0	0	0	0	0	0	0	1	0	2011
6656	168	489.8	5868475	0	0	0	0	0	0	0	0	0	0	1	0	2011
6713	168	531.1	6829199	0	0	0	0	0	0	0	0	0	0	1	0	2011
6781	168	544.4	7158707	0	0	0	0	0	0	0	0	0	0	0	0	2011
6700	71	550.0	3088808	0	0	0	0	0	0	0	0	0	0	0	0	2011
7516	104	472.9	3543799	0	0	0	0	0	0	0	0	0	0	0	1	2011
6714	168	505.5	6266301	0	0	0	0	0	0	0	0	0	0	0	0	2011
7604	168	465.8	5602499	1	0	0	0	0	0	0	0	0	0	0	0	2012
6685	168	497.8	6101146	1	0	0	0	0	0	0	0	0	0	0	0	2012
*6048	168	519.2	6522906	1	0	0	0	0	0	0	0	0	0	0	0	2012
6793	168	466.0	5305272	1	0	0	0	0	0	0	0	0	0	0	0	2012
6783	168	499.1	6081033	0	1	0	0	0	0	0	0	0	0	0	0	2012
6733	168	520.5	6575713	0	1	0	0	0	0	0	0	0	0	0	0	2012
6671	168	528.5	6771934	0	1	0	0	0	0	0	0	0	0	0	0	2012
6626	168	519.8	6532882	0	1	0	0	0	0	0	0	0	0	0	0	2012
7078	168	482.9	5758709	0	0	1	0	0	0	0	0	0	0	0	0	2012
6784	168	482.7	5758691	0	0	1	0	0	0	0	0	0	0	0	0	2012
6918	167	491.5	5910600	0	0	1	0	0	0	0	0	0	0	0	0	2012
6938	164	425.5	4616062	0	0	1	0	0	0	0	0	0	0	0	0	2012
6715	168	482.6	5726942	0	0	1	0	0	0	0	0	0	0	0	0	2012
6948	168	449.5	5121395	0	0	0	1	0	0	0	0	0	0	0	0	2012
6951	168	462.2	5461289	0	0	0	1	0	0	0	0	0	0	0	0	2012
6986	144	427.1	4062434	0	0	0	1	0	0	0	0	0	0	0	0	2012
*8143	11	241.8	152386	0	0	0	1	0	0	0	0	0	0	0	1	2012

Data Base for SMITH 3 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
6939	168	468.5	5543674	0	0	0	0	1	0	0	0	0	0	0	0	2012
7090	147	390.4	3731842	0	0	0	0	1	0	0	0	0	0	0	0	2012
6985	168	442.8	5033686	0	0	0	0	1	0	0	0	0	0	0	0	2012
6956	168	406.1	4467339	0	0	0	0	1	0	0	0	0	0	0	0	2012
6860	168	418.5	4637114	0	0	0	0	1	0	0	0	0	0	0	0	2012
7026	168	398.3	4287367	0	0	0	0	0	1	0	0	0	0	0	0	2012
7029	168	437.0	4982789	0	0	0	0	0	1	0	0	0	0	0	0	2012
6979	168	453.1	5281488	0	0	0	0	0	1	0	0	0	0	0	0	2012
6792	168	453.8	5315887	0	0	0	0	0	1	0	0	0	0	0	0	2012
6999	168	461.5	5388468	0	0	0	0	0	0	1	0	0	0	0	0	2012
6958	168	454.5	5257919	0	0	0	0	0	0	1	0	0	0	0	0	2012
7015	166	401.0	4274036	0	0	0	0	0	0	1	0	0	0	0	0	2012
7550	160	414.5	4483062	0	0	0	0	0	0	1	0	0	0	0	0	2012
6925	168	438.3	4884696	0	0	0	0	0	0	0	1	0	0	0	0	2012
7073	162	436.9	4860974	0	0	0	0	0	0	0	1	0	0	0	0	2012
6951	168	450.8	5222579	0	0	0	0	0	0	0	1	0	0	0	0	2012
6894	168	399.6	4342649	0	0	0	0	0	0	0	1	0	0	0	0	2012
6721	168	474.4	5691842	0	0	0	0	0	0	0	1	0	0	0	0	2012
6956	168	490.9	5888894	0	0	0	0	0	0	0	0	1	0	0	0	2012
6974	168	397.4	4266039	0	0	0	0	0	0	0	0	1	0	0	0	2012
6868	168	415.7	4594784	0	0	0	0	0	0	0	0	1	0	0	0	2012
6675	168	398.6	4331498	0	0	0	0	0	0	0	0	1	0	0	0	2012
6929	168	430.4	4872628	0	0	0	0	0	0	0	0	0	1	0	0	2012
6975	166	368.2	3686142	0	0	0	0	0	0	0	0	0	1	0	0	2012
6972	168	380.9	3933243	0	0	0	0	0	0	0	0	0	1	0	0	2012
6876	168	373.1	3833994	0	0	0	0	0	0	0	0	0	1	0	0	2012
6867	168	438.9	4911687	0	0	0	0	0	0	0	0	0	1	0	0	2012
6865	169	524.5	6806213	0	0	0	0	0	0	0	0	0	0	1	0	2012
3927	95	478.9	3287708	0	0	0	0	0	0	0	0	0	0	1	0	2012
6012	143	444.6	4318381	0	0	0	0	0	0	0	0	0	0	1	1	2012
6920	168	525.6	6781653	0	0	0	0	0	0	0	0	0	0	1	0	2012
6908	168	452.7	5172495	0	0	0	0	0	0	0	0	0	0	0	0	2012
4808	88	484.2	3207702	0	0	0	0	0	0	0	0	0	0	0	1	2012
6828	166	482.3	5786938	0	0	0	0	0	0	0	0	0	0	0	0	2012
7037	168	464.0	5471478	0	0	0	0	0	0	0	0	0	0	0	0	2012
6835	168	475.9	5471478	1	0	0	0	0	0	0	0	0	0	0	0	2013
6909	168	409.1	4362094	1	0	0	0	0	0	0	0	0	0	0	0	2013
6884	168	482.7	5752735	1	0	0	0	0	0	0	0	0	0	0	0	2013
6794	168	432.9	4727002	1	0	0	0	0	0	0	0	0	0	0	0	2013
6881	168	430.7	4841022	0	1	0	0	0	0	0	0	0	0	0	0	2013
6917	168	451.6	5002365	0	1	0	0	0	0	0	0	0	0	0	0	2013
6887	168	509.4	6368007	0	1	0	0	0	0	0	0	0	0	0	0	2013
6802	160	445.0	4689971	0	1	0	0	0	0	0	0	0	0	0	0	2013
6816	168	483.8	5729668	0	0	1	0	0	0	0	0	0	0	0	0	2013
6920	167	446.3	4988275	0	0	1	0	0	0	0	0	0	0	0	0	2013
6980	168	407.6	4376709	0	0	1	0	0	0	0	0	0	0	0	0	2013
*2950	71	465.7	2310669	0	0	1	0	0	0	0	0	0	0	0	0	2013

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
*12591	125	306.9	1995382	0	0	0	1	0	0	0	0	0	0	0	1	2013
6840	168	452.4	5184928	0	0	0	1	0	0	0	0	0	0	0	0	2013
6996	168	452.3	5327757	0	0	0	1	0	0	0	0	0	0	0	0	2013
7039	135	372.2	3086094	0	0	0	0	1	0	0	0	0	0	0	1	2013
6785	168	398.9	4302152	0	0	0	0	1	0	0	0	0	0	0	0	2013
7763	168	393.8	4244322	0	0	0	0	1	0	0	0	0	0	0	0	2013
6864	168	404.9	4475529	0	0	0	0	1	0	0	0	0	0	0	0	2013
7669	160	366.6	3813752	0	0	0	0	1	0	0	0	0	0	0	0	2013
6909	168	413.5	4434528	0	0	0	0	0	1	0	0	0	0	0	0	2013
6883	168	266.4	1871261	0	0	0	0	0	1	0	0	0	0	0	0	2013
6860	168	414.0	4575812	0	0	0	0	0	1	0	0	0	0	0	0	2013
6817	144	437.6	5010249	0	0	0	0	0	1	0	0	0	0	0	0	2013

HR — Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shut down 24 hours or more, in BTU/Kwh.

Hour — Number of hours the unit was synchronized during the week.

AMW — Average load on the unit, in MW.

LSRF — Load square range factor, in MW^2.

JAN to NOV — The number 1 indicates the month of the observation. All 0's indicate December.

NS — Number of start ups during the week after being shut down for 24 hours or more.

Year — The year of the observation.

* — Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2014 - December 2014

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 5	Jan '14	41.5	1,772	11,632	10,005	
	Feb '14	41.2	1,744	11,653	14,225	
	Mar '14	41.7	1,791	11,619	29,350	
	Apr '14	41.5	1,772	11,632	8,312	
	May '14	41.6	1,781	11,626	13,436	
	Jun '14	41.9	1,810	11,902	13,562	
	Jul '14	41.9	1,810	11,996	18,434	
	Aug '14	46.1	2,220	11,371	20,949	
	Sep '14	41.2	1,744	11,653	4,738	
	Oct '14	41.4	1,763	12,062	16,750	
	Nov '14	40.0	1,633	11,739	4,490	
	Dec '14	40.5	1,679	11,702	4,868	11,713
CRIST 6	Jan '14	125.3	16,599	12,353	79,194	
	Feb '14	123.1	15,965	12,438	24,990	
	Mar '14	125.5	16,657	12,346	46,815	
	Apr '14	125.1	16,541	12,765	82,838	
	May '14	125.2	16,570	11,432	53,969	
	Jun '14	125.3	16,599	12,353	71,664	
	Jul '14	125.5	16,657	12,882	58,860	
	Aug '14	132.9	18,847	12,092	84,681	
	Sep '14	125.5	16,657	12,346	86,850	
	Oct '14	125.5	16,657	12,346	89,736	
	Nov '14	125.1	16,541	11,823	81,579	
	Dec '14	125.3	16,599	12,353	71,539	12,294
CRIST 7	Jan '14	266.8	73,567	11,105	182,472	
	Feb '14	261.2	69,977	11,144	153,062	
	Mar '14	264.8	72,282	10,735	95,077	
	Apr '14	277.0	80,168	11,634	147,924	
	May '14	278.8	81,341	11,028	201,817	
	Jun '14	288.1	87,441	10,976	157,597	
	Jul '14	317.5	107,157	10,843	229,791	
	Aug '14	306.5	99,703	10,888	155,103	
	Sep '14	293.1	90,748	10,950	118,980	
	Oct '14	0.0	0	-	0	
	Nov '14	245.6	60,101	11,267	14,489	
	Dec '14	258.9	68,509	11,161	85,965	11,045

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3) * (4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2014 - December 2014

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKWH * 10^3 Generation	(5) Weighted ANOHR Target
SMITH 1	Jan '14	118.3	15,336	10,511	55,143	
	Feb '14	114.3	14,415	10,528	44,357	
	Mar '14	117.4	15,128	10,608	83,559	
	Apr '14	118.5	15,382	10,510	68,129	
	May '14	105.5	12,420	10,636	22,360	
	Jun '14	114.8	14,529	10,607	49,010	
	Jul '14	121.0	15,963	10,594	88,919	
	Aug '14	120.3	15,800	10,602	82,143	
	Sep '14	108.0	12,982	10,559	42,763	
	Oct '14	115.1	14,598	10,666	61,715	
	Nov '14	113.9	14,323	10,530	60,729	
	Dec '14	109.9	13,412	10,549	4,946	10,577
SMITH 2	Jan '14	111.2	14,305	10,664	55,475	
	Feb '14	109.2	13,816	10,850	45,105	
	Mar '14	109.5	13,890	10,513	11,717	
	Apr '14	108.0	13,525	10,609	30,675	
	May '14	91.8	9,716	10,782	49,387	
	Jun '14	91.4	9,625	11,009	28,160	
	Jul '14	95.1	10,473	10,971	42,340	
	Aug '14	117.2	15,793	10,795	52,616	
	Sep '14	91.8	9,716	11,005	39,188	
	Oct '14	109.5	13,890	10,848	36,467	
	Nov '14	108.5	13,646	10,676	30,915	
	Dec '14	110.0	14,012	10,844	76,890	10,814
SMITH 3	Jan '14	487.7	5,788,373	6,842	301,424	
	Feb '14	491.9	5,858,853	6,836	327,623	
	Mar '14	443.3	4,987,672	6,912	326,449	
	Apr '14	479.5	5,648,148	6,853	239,265	
	May '14	493.9	5,892,095	6,833	364,148	
	Jun '14	468.5	5,454,597	6,870	334,514	
	Jul '14	470.8	5,495,583	6,935	347,192	
	Aug '14	477.4	5,611,680	6,856	352,061	
	Sep '14	472.4	5,523,934	6,864	337,108	
	Oct '14	466.0	5,409,738	6,777	287,549	
	Nov '14	434.4	4,814,941	6,929	269,318	
	Dec '14	488.6	5,803,553	6,840	360,237	6,862

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on Page 2 of Schedule 1.

Column (5) = $(\Sigma ((3) * (4))) / (\Sigma (4))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2014 - December 2014

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 5	11,713	11,362	12,064
CRIST 6	12,294	11,925	12,663
CRIST 7	11,045	10,714	11,376
SMITH 1	10,577	10,260	10,894
SMITH 2	10,814	10,490	11,138
SMITH 3	6,862	6,656	7,068

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2014 - December 2014

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '14 - Dec '14	Reserve Shutdown Hours for Jan '14 - Dec '14	Target Equivalent Availability **
Crist 5	0.0160	720	4,197	91.0
Crist 6	0.0847	0	1,588	93.5
Crist 7	0.0588	1,560	1,388	78.1
Smith 1	0.0572	0	2,700	95.9
Smith 2	0.0721	0	3,663	96.4
Smith 3	0.0240	432	0	92.8

* For Period July 2008 through June 2013.

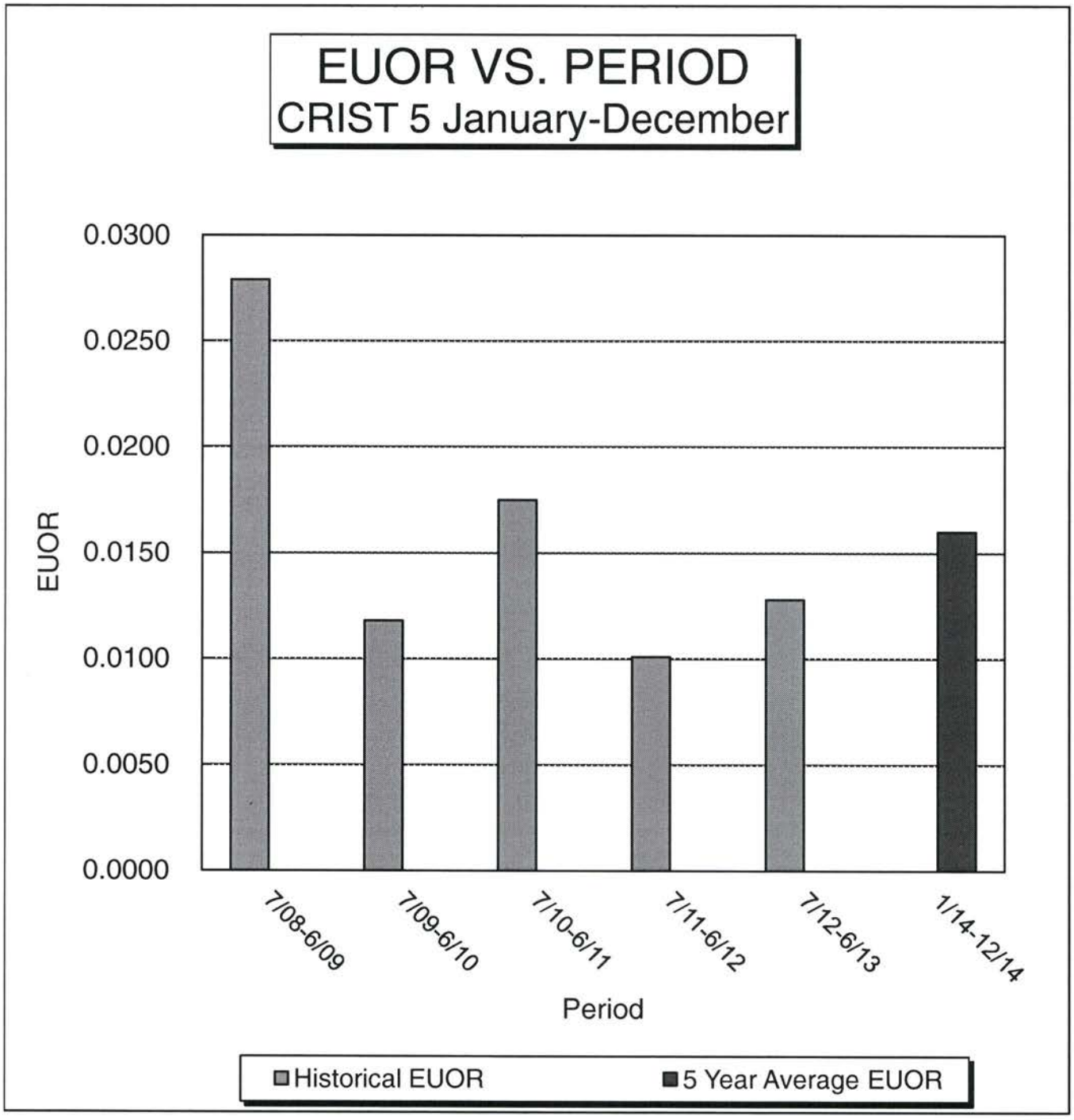
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

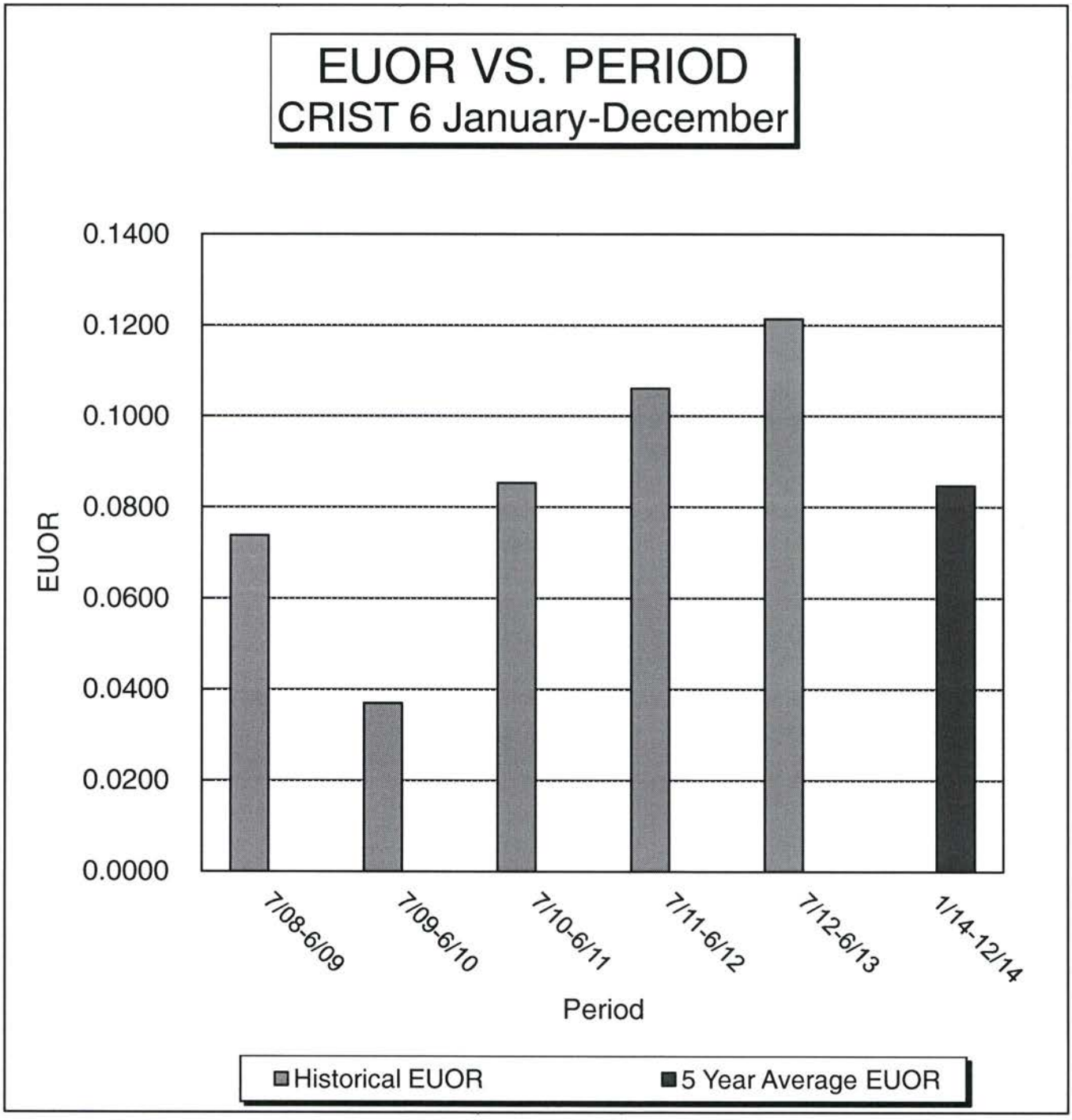
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2014 - December 2014

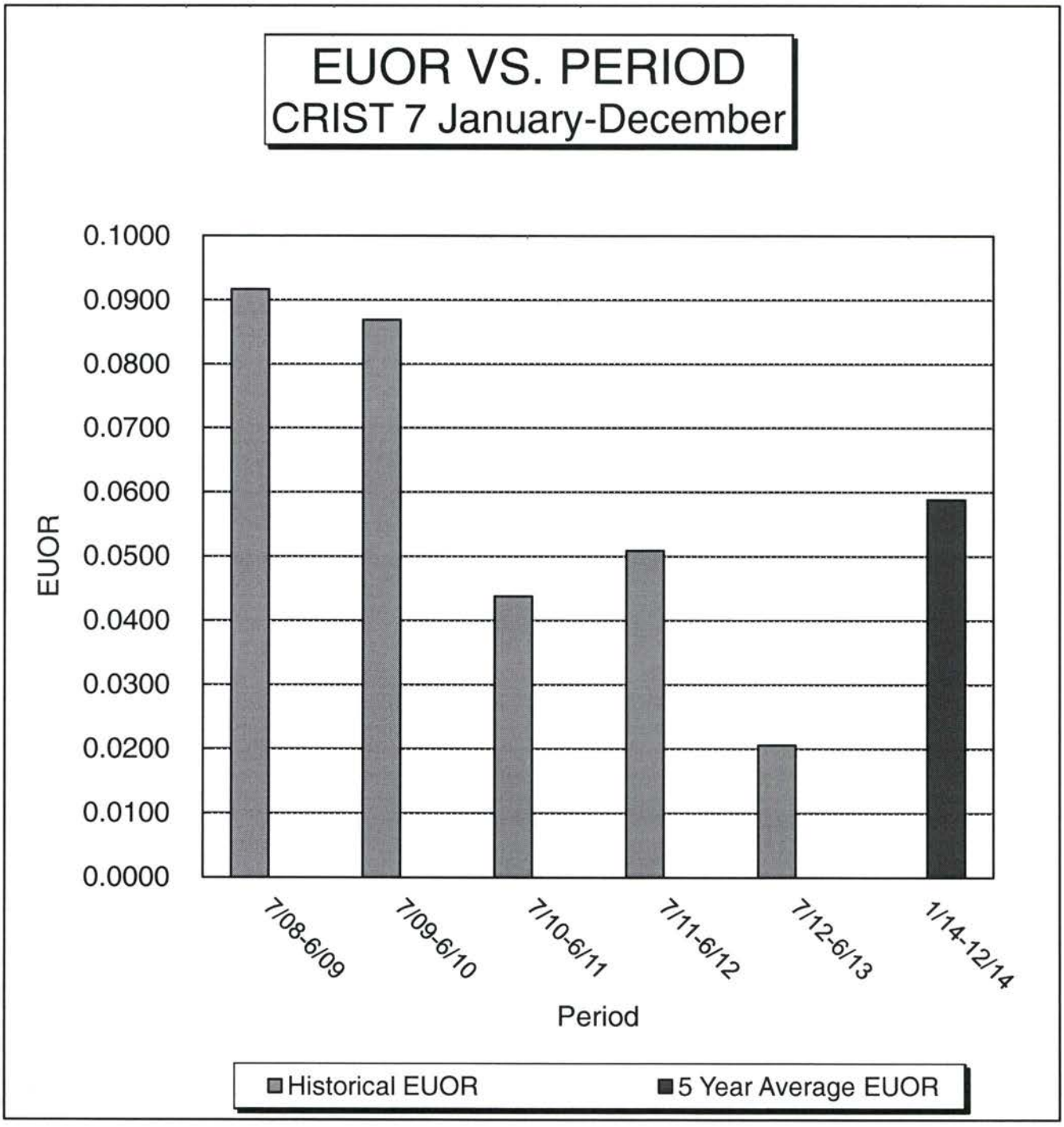
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 5	0.0160	0.0112	91.3	0.0232	90.8
Crist 6	0.0847	0.0593	95.1	0.1228	89.9
Crist 7	0.0588	0.0412	79.5	0.0853	76.5
Smith 1	0.0572	0.0400	97.2	0.0829	94.3
Smith 2	0.0721	0.0505	97.1	0.1045	93.9
Smith 3	0.0240	0.0168	93.5	0.0348	91.8

Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2014 - December 2014

Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 5	91.0	91.3	90.8
Crist 6	93.5	95.1	89.9
Crist 7	78.1	79.5	76.5
Smith 1	95.9	97.2	94.3
Smith 2	96.4	97.1	93.9
Smith 3	92.8	93.5	91.8


EUOR VS. PERIOD
CRIST 5 January-December
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
EUOR
7/08-6/09
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
1/14-12/14
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 6 January-December
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/08-6/09
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
1/14-12/14
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
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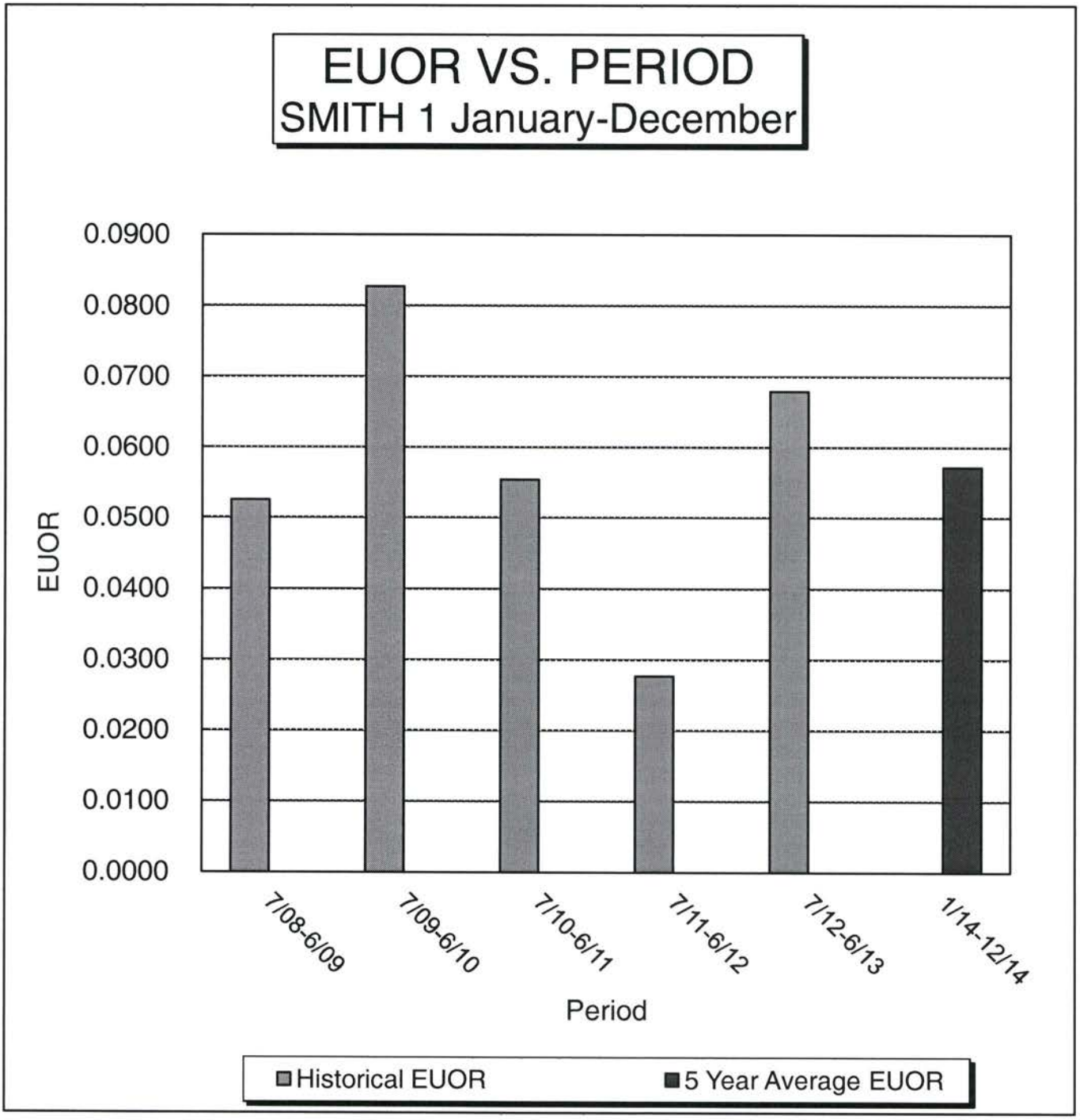
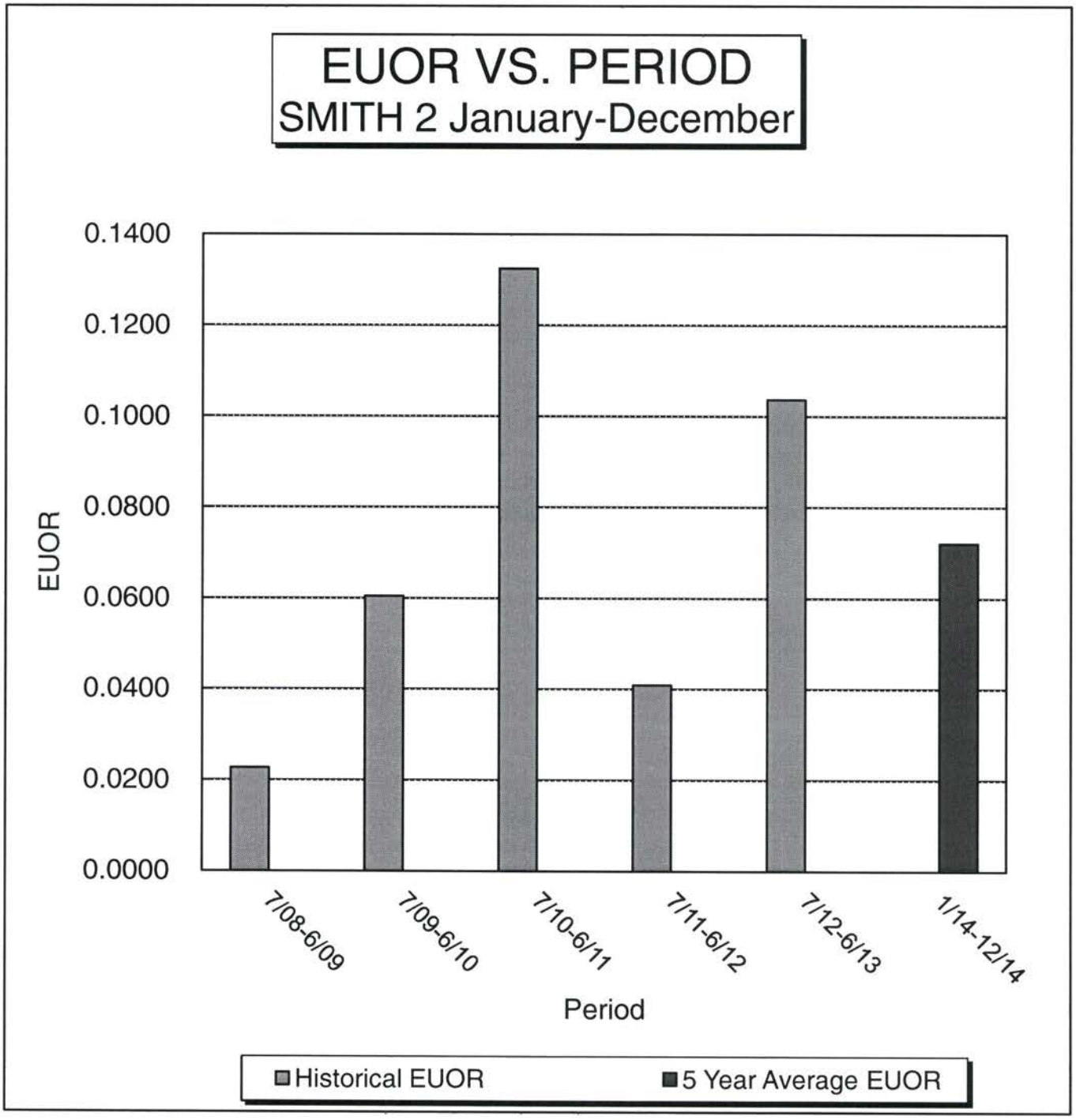
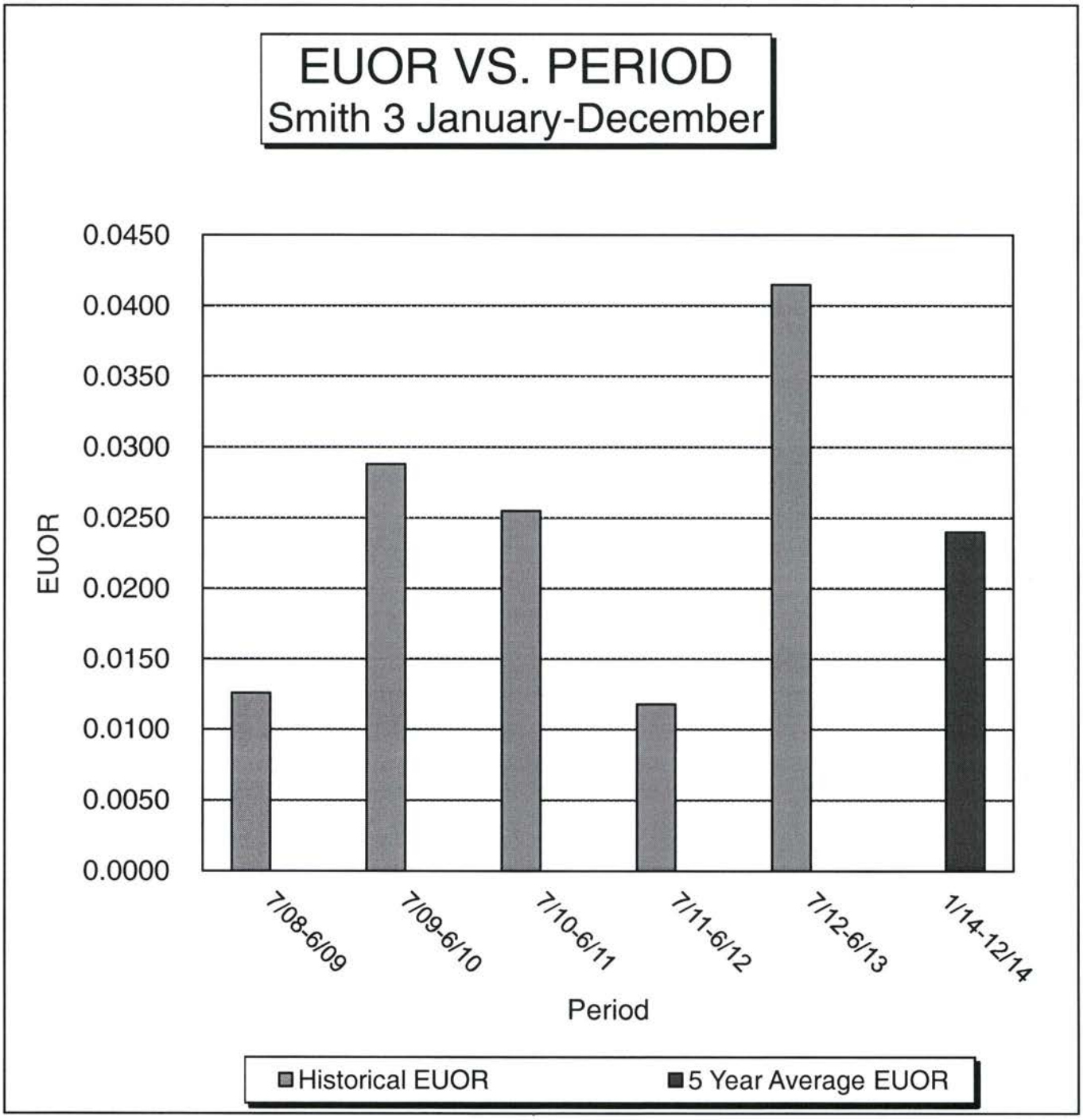
0.0900
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/08-6/09
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
1/14-12/14
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 1 January-December
0.0900
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/08-6/09
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
1/14-12/14
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 2 January-December
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/08-6/09
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
1/14-12/14
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
Smith 3 January-December
0.0450
0.0400
0.0350
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
EUOR
7/08-6/09
7/09-6/10
7/10-6/11
7/11-6/12
7/12-6/13
1/14-12/14
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2014 - DECEMBER 2014

CONTENTS

SCHEDULE 3
PAGE

GPIF Reward/Penalty Table (Estimated)	3
GPIF Calculation of Maximum Allowed Incentive Dollars	4
GPIF Target and Range Summary	5
Comparison of GPIF Targets vs. Prior Seasons' Actual Performance for Availability	6 - 7
Comparison of GPIF Targets vs. Prior Seasons' Actual Performance for ANOHR	8
Example Calculation of Prior Season ANOHR	9
Derivation of Weighting Factors	10
GPIF Unit Point Tables	11 - 16
Estimated Unit Performance Data	17 - 29
Planned Outage Schedules	30 - 31

Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2014 - December 2014

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	8947	5208
+ 9	8052	4688
+ 8	7158	4167
+ 7	6263	3646
+ 6	5368	3125
+ 5	4474	2604
+ 4	3579	2083
+ 3	2684	1563
+ 2	1789	1042
+ 1	895	521
0	0	0
- 1	-888	-521
- 2	-1777	-1042
- 3	-2665	-1563
- 4	-3554	-2083
- 5	-4442	-2604
- 6	-5330	-3125
- 7	-6219	-3646
- 8	-7107	-4167
- 9	-7996	-4688
- 10	-8884	-5208
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

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Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2014 - December 2014

Line 1	Beginning of Period Balance of Common Equity	$1,255,018,711
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '14	$1,311,459,609
Line 3	Month of Feb '14	$1,315,743,321
Line 4	Month of Mar '14	$1,323,130,379
Line 5	Month of Apr '14	$1,297,074,708
Line 6	Month of May '14	$1,306,383,027
Line 7	Month of Jun '14	$1,321,939,998
Line 8	Month of Jul '14	$1,309,287,738
Line 9	Month of Aug '14	$1,326,358,719
Line 10	Month of Sep '14	$1,340,722,420
Line 11	Month of Oct '14	$1,315,507,500
Line 12	Month of Nov '14	$1,319,437,818
Line 13	Month of Dec '14	$1,355,637,296
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,315,207,788
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.1928%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$5,373,213
Line 18	Jurisdictional Sales (KWH)	11,096,542,668
Line 19	Total Territorial Sales (KWH)	11,447,591,023
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.9334%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$5,208,440

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2014 - December 2014

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 5	0.0%	91.0	91.3	90.8	$1	($1)
Crist 6	0.0%	93.5	95.1	89.9	$3	($7)
Crist 7	0.9%	78.1	79.5	76.5	$79	($89)
Smith 1	0.1%	95.9	97.2	94.3	$6	($24)
Smith 2	0.2%	96.4	97.1	93.9	$14	($1)
Smith 3	1.9%	92.8	93.5	91.8	$172	($90)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 5	2.4%	11,713	56.1	11,362	12,064	$217	($217)
Crist 6	13.4%	12,294	42.4	11,925	12,663	$1,201	($1,201)
Crist 7	20.7%	11,045	60.6	10,714	11,376	$1,851	($1,851)
Smith 1	10.8%	10,577	71.8	10,260	10,894	$969	($969)
Smith 2	8.5%	10,814	53.4	10,490	11,138	$760	($760)
Smith 3	41.1%	6,862	92.7	6,656	7,068	$3,674	($3,674)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2014 - December 2014

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '012 - Jun '013			Actual Performance 2nd Prior Period Jul '011 - Jun '012		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 5	0.0%	0.4%	0.0822	0.0075	0.0160	0.0000	0.0105	0.0128	0.1981	0.0074	0.0101
Crist 6	0.0%	1.1%	0.0000	0.0648	0.0847	0.0000	0.0605	0.1214	0.2197	0.0661	0.1061
Crist 7	0.9%	28.7%	0.1781	0.0407	0.0588	0.2632	0.0133	0.0206	0.0000	0.0470	0.0509
Smith 1	0.1%	2.2%	0.0000	0.0408	0.0572	0.0000	0.0586	0.0679	0.1261	0.0230	0.0277
Smith 2	0.2%	5.1%	0.0000	0.0360	0.0721	0.0000	0.0619	0.1037	0.0000	0.0207	0.0409
Smith 3	1.9%	62.5%	0.0493	0.0228	0.0240	0.0654	0.0386	0.0415	0.0390	0.0113	0.0118
Weighted GPIF System Average			0.0823	0.0294	0.0378	0.1165	0.0331	0.0400	0.0303	0.0229	0.0259

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2014 - December 2014

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '010 - Jun '011			Actual Performance 4th Prior Period Jul '09 - Jun '010			Actual Performance 5th Prior Period Jul '08 - Jun '09		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 5	0.0%	0.4%	0.0411	0.0152	0.0175	0.0694	0.0105	0.0118	0.0000	0.0253	0.0279
Crist 6	0.0%	1.1%	0.2576	0.0495	0.0853	0.0626	0.0254	0.0370	0.1549	0.0475	0.0738
Crist 7	0.9%	28.7%	0.0867	0.0398	0.0438	0.1773	0.0715	0.0869	0.1367	0.0752	0.0917
Smith 1	0.1%	2.2%	0.0631	0.0494	0.0554	0.0000	0.0686	0.0827	0.0735	0.0367	0.0525
Smith 2	0.2%	5.1%	0.0932	0.0935	0.1325	0.0000	0.0519	0.0605	0.0272	0.0214	0.0227
Smith 3	1.9%	62.5%	0.0460	0.0240	0.0255	0.1999	0.0212	0.0288	0.0869	0.0097	0.0126
Weighted GPIF System Average			0.0628	0.0329	0.0375	0.1769	0.0383	0.0483	0.0983	0.0302	0.0374

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2014 - December 2014

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '012 - Jun '013	2nd Prior Period Heat Rate Jul '011 - Jun '012	3rd Prior Period Heat Rate Jul '010 - Jun '011
Crist 5	2.4%	2.5%	11,713	11,638	11,693	11,700
Crist 6	13.4%	13.8%	12,294	12,296	12,112	12,402
Crist 7	20.7%	21.3%	11,045	10,892	11,211	10,990
Smith 1	10.8%	11.2%	10,577	10,643	10,516	10,605
Smith 2	8.5%	8.8%	10,814	10,856	10,721	10,833
Smith 3	41.1%	42.4%	6,862	6,616	6,612	6,611
Weighted GPIF System Average:			9,390	9,263	9,279	9,291

Issued by: S. W. Connally, Jr.

Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '011 - Jun '012

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun
1. Target Heat Rate*	12882.0 12353.0	12092.0 12438.0	12346.0 12346.0	12346.0 12765.0	11823.0 11432.0	12353.0 12353.0
2. Target Heat Rate at Actual Conditions**	12118.0 11733.0	11427.0 0.0	11749.0 0.0	12175.0 12648.0	11711.0 10481.0	12087.0 10855.0
3. Adjustments to Actual Heat Rate (1-2)	764.0 620.0	665.0 12438.0	597.0 12346.0	171.0 117.0	112.0 951.0	266.0 1498.0
4. Actual Heat Rate for Prior Period	12049.0 11889.0	11178.0 0.0	11521.0 0.0	12207.0 12198.0	11389.0 10255.0	11947.0 10349.0
5. Adjusted actual Heat Rate (4+3)	12813.0 12509.0	11843.0 12438.0	12118.0 12346.0	12378.0 12315.0	11501.0 11206.0	12213.0 11847.0
6. Forecast Net MWH Generation*	58859.5 79194.3	84681.2 24989.7	86849.8 46815.3	89736.3 82837.6	81578.8 53968.7	71538.8 71664.3

7. Adjusted Actual Heat Rate for Jul '011 - Jun '012 = $(\Sigma ((5) * (6))) / (\Sigma (6))$ 12,112

* For the January 2014 - December 2014 time period.

** Based on the target heat rate equation from Page 2 of Schedule 1 using actual rather than forecast variable values.

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Derivation of Weighting Factors

Gulf Power Company

Period of: January 2014 - December 2014

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 5	EA-2	$491,709	$491,708	$1	0.0%
Crist 5	ANOHR-2	$491,709	$491,492	$217	2.4%
Crist 6	EA-3	$491,709	$491,706	$3	0.0%
Crist 6	ANOHR-3	$491,709	$490,508	$1,201	13.4%
Crist 7	EA-4	$491,709	$491,630	$79	0.9%
Crist 7	ANOHR-4	$491,709	$489,858	$1,851	20.7%
Smith 1	EA-5	$491,709	$491,703	$6	0.1%
Smith 1	ANOHR-5	$491,709	$490,740	$969	10.8%
Smith 2	EA-6	$491,709	$491,695	$14	0.2%
Smith 2	ANOHR-6	$491,709	$490,949	$760	8.5%
Smith 3	EA-7	$491,709	$491,537	$172	1.9%
Smith 3	ANOHR-7	$491,709	$488,035	$3,674	41.1%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2014 - December 2014

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	1	91.30	+ 10	217	11,362
+ 9	1	91.28	+ 9	195	11,390
+ 8	1	91.26	+ 8	174	11,417
+ 7	1	91.24	+ 7	152	11,445
+ 6	1	91.22	+ 6	130	11,472
+ 5	1	91.20	+ 5	109	11,500
+ 4	0	91.18	+ 4	87	11,528
+ 3	0	91.16	+ 3	65	11,555
+ 2	0	91.14	+ 2	43	11,583
+ 1	0	91.12	+ 1	22	11,610
				0	11,638
0	0	91.10	0	0	11,713
				0	11,788
- 1	(0)	91.07	- 1	(22)	11,816
- 2	(0)	91.04	- 2	(43)	11,843
- 3	(0)	91.01	- 3	(65)	11,871
- 4	(0)	90.98	- 4	(87)	11,898
- 5	(1)	90.95	- 5	(109)	11,926
- 6	(1)	90.92	- 6	(130)	11,954
- 7	(1)	90.89	- 7	(152)	11,981
- 8	(1)	90.86	- 8	(174)	12,009
- 9	(1)	90.83	- 9	(195)	12,036
- 10	(1)	90.80	- 10	(217)	12,064
Weighting Factor:		0.000	Weighting Factor:		0.024

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2014 - December 2014

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	3	95.10	+ 10	1,201	11,925
+ 9	3	94.90	+ 9	1,081	11,954
+ 8	2	94.70	+ 8	961	11,984
+ 7	2	94.50	+ 7	841	12,013
+ 6	2	94.30	+ 6	721	12,043
+ 5	2	94.10	+ 5	601	12,072
+ 4	1	93.90	+ 4	480	12,101
+ 3	1	93.70	+ 3	360	12,131
+ 2	1	93.50	+ 2	240	12,160
+ 1	0	93.30	+ 1	120	12,190
				0	12,219
0	0	93.10	0	0	12,294
				0	12,369
- 1	(1)	92.78	- 1	(120)	12,398
- 2	(1)	92.46	- 2	(240)	12,428
- 3	(2)	92.14	- 3	(360)	12,457
- 4	(3)	91.82	- 4	(480)	12,487
- 5	(4)	91.50	- 5	(601)	12,516
- 6	(4)	91.18	- 6	(721)	12,545
- 7	(5)	90.86	- 7	(841)	12,575
- 8	(6)	90.54	- 8	(961)	12,604
- 9	(6)	90.22	- 9	(1,081)	12,634
- 10	(7)	89.90	- 10	(1,201)	12,663
Weighting Factor:		0.000	Weighting Factor:		0.134

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2014 - December 2014

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	79	79.50	+ 10	1,851	10,714
+ 9	71	79.38	+ 9	1,666	10,740
+ 8	63	79.26	+ 8	1,481	10,765
+ 7	55	79.14	+ 7	1,296	10,791
+ 6	47	79.02	+ 6	1,111	10,816
+ 5	40	78.90	+ 5	926	10,842
+ 4	32	78.78	+ 4	740	10,868
+ 3	24	78.66	+ 3	555	10,893
+ 2	16	78.54	+ 2	370	10,919
+ 1	8	78.42	+ 1	185	10,944
				0	10,970
0	0	78.30	0	0	11,045
				0	11,120
- 1	(9)	78.12	- 1	(185)	11,146
- 2	(18)	77.94	- 2	(370)	11,171
- 3	(27)	77.76	- 3	(555)	11,197
- 4	(36)	77.58	- 4	(740)	11,222
- 5	(45)	77.40	- 5	(926)	11,248
- 6	(53)	77.22	- 6	(1,111)	11,274
- 7	(62)	77.04	- 7	(1,296)	11,299
- 8	(71)	76.86	- 8	(1,481)	11,325
- 9	(80)	76.68	- 9	(1,666)	11,350
- 10	(89)	76.50	- 10	(1,851)	11,376
Weighting Factor:		0.009	Weighting Factor:		0.207

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2014 - December 2014

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	6	97.20	+ 10	969	10,260
+ 9	5	97.08	+ 9	872	10,284
+ 8	5	96.96	+ 8	775	10,308
+ 7	4	96.84	+ 7	678	10,333
+ 6	4	96.72	+ 6	581	10,357
+ 5	3	96.60	+ 5	485	10,381
+ 4	2	96.48	+ 4	388	10,405
+ 3	2	96.36	+ 3	291	10,429
+ 2	1	96.24	+ 2	194	10,454
+ 1	1	96.12	+ 1	97	10,478
				0	10,502
0	0	96.00	0	0	10,577
				0	10,652
- 1	(2)	95.83	- 1	(97)	10,676
- 2	(5)	95.66	- 2	(194)	10,700
- 3	(7)	95.49	- 3	(291)	10,725
- 4	(10)	95.32	- 4	(388)	10,749
- 5	(12)	95.15	- 5	(485)	10,773
- 6	(14)	94.98	- 6	(581)	10,797
- 7	(17)	94.81	- 7	(678)	10,821
- 8	(19)	94.64	- 8	(775)	10,846
- 9	(22)	94.47	- 9	(872)	10,870
- 10	(24)	94.30	- 10	(969)	10,894
Weighting Factor:		0.001	Weighting Factor:		0.108

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2014 - December 2014

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	14	97.10	+ 10	760	10,490
+ 9	13	96.97	+ 9	684	10,515
+ 8	11	96.84	+ 8	608	10,540
+ 7	10	96.71	+ 7	532	10,565
+ 6	8	96.58	+ 6	456	10,590
+ 5	7	96.45	+ 5	380	10,615
+ 4	6	96.32	+ 4	304	10,639
+ 3	4	96.19	+ 3	228	10,664
+ 2	3	96.06	+ 2	152	10,689
+ 1	1	95.93	+ 1	76	10,714
				0	10,739
0	0	95.80	0	0	10,814
				0	10,889
- 1	(0)	95.61	- 1	(76)	10,914
- 2	(0)	95.42	- 2	(152)	10,939
- 3	(0)	95.23	- 3	(228)	10,964
- 4	(0)	95.04	- 4	(304)	10,989
- 5	(1)	94.85	- 5	(380)	11,014
- 6	(1)	94.66	- 6	(456)	11,038
- 7	(1)	94.47	- 7	(532)	11,063
- 8	(1)	94.28	- 8	(608)	11,088
- 9	(1)	94.09	- 9	(684)	11,113
- 10	(1)	93.90	- 10	(760)	11,138
Weighting Factor:		0.002	Weighting Factor:		0.085

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2014 - December 2014

Smith 3

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	172	93.50	+ 10	3,674	6,656
+ 9	155	93.43	+ 9	3,307	6,669
+ 8	138	93.36	+ 8	2,939	6,682
+ 7	120	93.29	+ 7	2,572	6,695
+ 6	103	93.22	+ 6	2,204	6,708
+ 5	86	93.15	+ 5	1,837	6,722
+ 4	69	93.08	+ 4	1,470	6,735
+ 3	52	93.01	+ 3	1,102	6,748
+ 2	34	92.94	+ 2	735	6,761
+ 1	17	92.87	+ 1	367	6,774
				0	6,787
0	0	92.80	0	0	6,862
				0	6,937
- 1	(9)	92.70	- 1	(367)	6,950
- 2	(18)	92.60	- 2	(735)	6,963
- 3	(27)	92.50	- 3	(1,102)	6,976
- 4	(36)	92.40	- 4	(1,470)	6,989
- 5	(45)	92.30	- 5	(1,837)	7,003
- 6	(54)	92.20	- 6	(2,204)	7,016
- 7	(63)	92.10	- 7	(2,572)	7,029
- 8	(72)	92.00	- 8	(2,939)	7,042
- 9	(81)	91.90	- 9	(3,307)	7,055
- 10	(90)	91.80	- 10	(3,674)	7,068
Weighting Factor:		0.019	Weighting Factor:		0.411

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	CRIST 5	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14	
1.	EAF (%)	93.5	99.9	99.6	36.7	64.5	99.6	
2.	POF (%)	0.0	0.0	0.0	63.3	35.5	0.0	
3.	EUOF (%)	6.5	0.1	0.4	0.0	0.0	0.4	
4.	EUOR (%)	16.6	0.3	0.4	0.0	0.0	1.0	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	241.1	344.9	703.3	200.2	323.1	324.0	
7.	RSH	454.9	327.1	39.7	63.8	156.9	392.8	
8.	UH	48.0	0.0	0.0	456.0	264.0	3.2	
9.	POH	0.0	0.0	0.0	456.0	264.0	0.0	
10.	FOH & EFOH	0.0	1.0	3.0	0.0	0.0	3.2	
11.	MOH & EMOH	48.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	116378.0	165769.0	341013.0	96683.0	156205.0	161413.0	
13.	Net Gen (MWH)	10005.0	14225.4	29349.6	8311.8	13435.8	13561.8	
14.	ANOHR (Btu/KWH)	11632.0	11653.0	11619.0	11632.0	11626.0	11902.0	
15.	NOF %	55.3	55.0	55.6	55.4	55.4	55.8	
16.	NPC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	

19.	ANOHR Equation	10^6 / AKW * [230.19 + 12.41 * JUN + 16.35 * JUL + 17.53 * OCT] + 3,801 + 0.05350 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	CRIST 5	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1.	EAF (%)	99.6	99.6	99.6	100.0	99.9	100.0	91.0
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3.	EUOF (%)	0.4	0.4	0.4	0.0	0.1	0.0	0.8
4.	EUOR (%)	0.7	0.7	2.7	0.0	0.9	0.0	1.7
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	440.0	454.0	115.0	404.3	112.2	120.3	3782.2
7.	RSH	300.7	286.7	601.8	339.7	608.8	623.7	4196.9
8.	UH	3.3	3.3	3.2	0.0	0.0	0.0	780.9
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	720.0
10.	FOH & EFOH	3.3	3.3	3.2	0.0	1.0	0.0	17.9
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	48.0
12.	Oper MBtu	221132.0	238211.0	55207.0	202034.0	52706.0	56963.0	1863714.0
13.	Net Gen (MWH)	18433.8	20949.0	4737.6	16749.6	4489.8	4867.8	159117.0
14.	ANOHR (Btu/KWH)	11996.0	11371.0	11653.0	12062.0	11739.0	11702.0	11713.0
15.	NOF %	55.9	61.5	54.9	55.2	53.4	54.0	56.1
16.	NPC (MW)	75.0	75.0	75.0	75.0	75.0	75.0	75.0

19.	ANOHR Equation	10^6 / AKW * [230.19 + 12.41 * JUN + 16.35 * JUL + 17.53 * OCT] + 3,801 + 0.05350 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	CRIST 6	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14	
1.	EAF (%)	97.0	62.6	87.6	96.8	96.8	96.9	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	3.0	37.4	12.4	3.2	3.2	3.1	
4.	EUOR (%)	3.4	55.3	19.8	3.4	5.3	3.7	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	632.0	203.0	373.0	662.0	431.0	572.0	
7.	RSH	90.0	218.0	278.0	36.0	291.0	126.0	
8.	UH	22.0	251.0	92.0	22.0	22.0	22.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	22.0	11.0	20.0	23.0	24.0	22.0	
11.	MOH & EMOH	0.0	240.0	72.0	0.0	0.0	0.0	
12.	Oper MBtu	978287.0	310822.0	577982.0	1057422.0	616970.0	885269.0	
13.	Net Gen (MWH)	79194.3	24989.7	46815.3	82837.6	53968.7	71664.3	
14.	ANOHR (Btu/KWH)	12353.0	12438.0	12346.0	12765.0	11432.0	12353.0	
15.	NOF %	43.1	42.3	43.1	43.0	41.7	41.8	
16.	NPC (MW)	291.0	291.0	291.0	291.0	300.0	300.0	

19.	ANOHR Equation	10^6 / AKW * [1012.40 + 50.51 * APR - 115.89 * MAY + 67.27 * JUL - 67.36 * NOV] + 1,428 + 0.02148 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	CRIST 6	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1.	EAF (%)	97.0	97.0	96.9	96.8	96.9	97.0	93.5
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	3.0	3.0	3.1	3.2	3.1	3.0	6.5
4.	EUOR (%)	4.5	3.3	3.1	3.3	3.3	3.7	7.9
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	469.0	637.0	692.1	715.1	652.0	571.0	6609.2
7.	RSH	253.0	85.0	5.9	6.9	47.0	151.0	1587.8
8.	UH	22.0	22.0	22.0	22.0	22.0	22.0	563.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	22.0	22.0	22.0	24.0	22.0	22.0	256.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	312.0
12.	Oper MBtu	758228.0	1023965.0	1072248.0	1107884.0	964506.0	883719.0	10237302.0
13.	Net Gen (MWH)	58859.5	84681.2	86849.8	89736.3	81578.8	71538.8	832714.3
14.	ANOHR (Btu/KWH)	12882.0	12092.0	12346.0	12346.0	11823.0	12353.0	12294.0
15.	NOF %	41.8	44.3	41.8	41.8	41.7	41.8	42.4
16.	NPC (MW)	300.0	300.0	300.0	300.0	300.0	300.0	297.0

19.	ANOHR Equation	10^6 / AKW * [1012.40 + 50.51 * APR - 115.89 * MAY + 67.27 * JUL - 67.36 * NOV] + 1,428 + 0.02148 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	CRIST 7	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14	
1.	EAF (%)	97.6	97.8	78.7	90.8	97.8	97.8	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	2.4	2.2	21.3	9.2	2.2	2.2	
4.	EUOR (%)	2.6	2.5	30.6	11.0	2.2	2.8	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	684.0	586.0	359.0	534.0	723.8	547.0	
7.	RSH	44.0	72.0	226.0	122.0	4.2	157.0	
8.	UH	16.0	14.0	158.0	64.0	16.0	16.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	18.0	15.0	14.0	18.0	16.0	16.0	
11.	MOH & EMOH	0.0	0.0	144.0	48.0	0.0	0.0	
12.	Oper MBtu	2026353.0	1705717.0	1020649.0	1720947.0	2225640.0	1729789.0	
13.	Net Gen (MWH)	182472.1	153061.5	95076.8	147923.9	201817.2	157597.4	
14.	ANOHR (Btu/KWH)	11105.0	11144.0	10735.0	11634.0	11028.0	10976.0	
15.	NOF %	57.4	56.2	57.0	59.6	60.0	62.0	
16.	NPC (MW)	465.0	465.0	465.0	465.0	465.0	465.0	

19.	ANOHR Equation	10^6 / AKW * [1373.91 - 101.46 * MAR + 164.88 * APR] + 3,451 + 0.00908 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	CRIST 7	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1.	EAF (%)	97.7	97.6	61.9	0.0	22.8	97.6	78.1
2.	POF (%)	0.0	0.0	36.7	100.0	76.6	0.0	17.8
3.	EUOF (%)	2.3	2.4	1.4	0.0	0.6	2.4	4.1
4.	EUOR (%)	2.3	3.4	2.4	0.0	7.2	5.1	6.1
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	723.8	506.0	406.0	0.0	59.0	332.0	5460.5
7.	RSH	3.2	220.0	40.0	0.0	105.4	394.0	1387.9
8.	UH	17.0	18.0	274.0	744.0	556.6	18.0	1911.6
9.	POH	0.0	0.0	264.0	744.0	552.0	0.0	1560.0
10.	FOH & EFOH	17.0	18.0	10.0	0.0	4.6	18.0	164.6
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	192.0
12.	Oper MBtu	2491625.0	1688765.0	1302830.0	0.0	163243.0	959459.0	17035017.0
13.	Net Gen (MWH)	229791.1	155103.3	118979.9	0.0	14488.6	85965.3	1542277.1
14.	ANOHR (Btu/KWH)	10843.0	10888.0	10950.0	-	11267.0	11161.0	11045.0
15.	NOF %	68.3	65.9	63.0	0.0	52.0	54.9	60.6
16.	NPC (MW)	465.0	465.0	465.0	465.0	472.0	472.0	466.2

19.	ANOHR Equation	10^6 / AKW * [1373.91 - 101.46 * MAR + 164.88 * APR] + 3,451 + 0.00908 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	SMITH 1	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14	
1.	EAF (%)	98.9	99.0	99.1	99.3	99.2	99.3	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.1	1.0	0.9	0.7	0.8	0.7	
4.	EUOR (%)	1.7	1.8	1.0	0.9	2.8	1.2	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	466.0	388.0	712.0	575.0	212.0	427.0	
7.	RSH	272.0	279.0	25.0	140.0	526.0	288.0	
8.	UH	6.0	5.0	6.0	5.0	6.0	5.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	8.0	7.0	7.0	5.0	6.0	5.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	579606.0	466990.0	886394.0	716032.0	237817.0	519846.0	
13.	Net Gen (MWH)	55142.8	44357.0	83559.0	68128.6	22359.6	49009.7	
14.	ANOHR (Btu/KWH)	10511.0	10528.0	10608.0	10510.0	10636.0	10607.0	
15.	NOF %	73.0	70.6	72.4	73.1	65.1	70.8	
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [59.93 + 11.03 * MAR + 6.71 * MAY + 9.25 * JUN + 11.47 * JUL + 12.00 * AUG + 16.27 * OCT] + 10,004

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	SMITH 1	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1.	EAF (%)	99.2	99.2	99.3	99.2	92.6	67.3	95.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	0.8	0.8	0.7	0.8	7.4	32.7	4.1
4.	EUOR (%)	0.8	0.9	1.2	1.1	9.0	84.4	5.9
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	735.0	683.0	396.0	536.0	533.0	45.0	5708.0
7.	RSH	3.0	55.0	319.0	202.0	135.0	456.0	2700.0
8.	UH	6.0	6.0	5.0	6.0	53.0	243.0	352.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	6.0	6.0	5.0	6.0	5.0	3.0	69.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	240.0	288.0
12.	Oper MBtu	942012.0	870882.0	451536.0	658248.0	639476.0	52175.0	7021014.0
13.	Net Gen (MWH)	88919.4	82143.2	42763.1	61714.6	60729.0	4946.0	663772.0
14.	ANOHR (Btu/KWH)	10594.0	10602.0	10559.0	10666.0	10530.0	10549.0	10577.0
15.	NOF %	74.7	74.2	66.7	71.1	70.3	67.8	71.8
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19.	ANOHR Equation	10^6 / AKW * [59.93 + 11.03 * MAR + 6.71 * MAY + 9.25 * JUN + 11.47 * JUL + 12.00 * AUG + 16.27 * OCT] + 10,004

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	SMITH 2	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14	
1.	EAF (%)	99.7	99.7	99.7	59.9	99.7	99.7	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	0.3	0.3	0.3	40.1	0.3	0.3	
4.	EUOR (%)	0.4	0.5	1.8	50.4	0.4	0.6	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	499.0	413.0	107.0	284.0	538.0	308.0	
7.	RSH	243.0	257.0	634.0	147.0	204.0	410.0	
8.	UH	2.0	2.0	2.0	289.0	2.0	2.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	2.0	2.0	2.0	1.0	2.0	2.0	
11.	MOH & EMOH	0.0	0.0	0.0	288.0	0.0	0.0	
12.	Oper MBtu	591581.0	489387.0	123185.0	325432.0	532495.0	310009.0	
13.	Net Gen (MWH)	55474.6	45104.8	11717.4	30675.1	49387.4	28159.6	
14.	ANOHR (Btu/KWH)	10664.0	10850.0	10513.0	10609.0	10782.0	11009.0	
15.	NOF %	57.0	56.0	56.2	55.4	47.1	46.9	
16.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	

19.	ANOHR Equation	10^6 / AKW * [89.09 - 19.11 * JAN - 36.70 * MAR - 27.06 * APR - 20.50 * MAY - 19.52 * NOV] + 10,035

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	SMITH 2	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1.	EAF (%)	99.7	99.7	99.7	99.5	99.4	99.7	96.4
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	0.3	0.3	0.3	0.5	0.6	0.3	3.6
4.	EUOR (%)	0.4	0.4	0.5	1.2	1.4	0.3	6.2
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	445.0	449.0	427.0	333.0	285.0	699.0	4787.0
7.	RSH	297.0	293.0	291.0	409.0	434.0	44.0	3663.0
8.	UH	2.0	2.0	2.0	2.0	2.0	1.0	310.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	2.0	2.0	2.0	4.0	4.0	2.0	27.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	288.0
12.	Oper MBtu	464509.0	567984.0	431268.0	395598.0	330046.0	833795.0	5395289.0
13.	Net Gen (MWH)	42339.7	52615.5	39188.4	36467.4	30914.8	76890.0	498934.7
14.	ANOHR (Btu/KWH)	10971.0	10795.0	11005.0	10848.0	10676.0	10844.0	10814.0
15.	NOF %	48.8	60.1	47.1	56.2	55.6	56.4	53.4
16.	NPC (MW)	195.0	195.0	195.0	195.0	195.0	195.0	195.0

19.	ANOHR Equation	10^6 / AKW * [89.09 - 19.11 * JAN - 36.70 * MAR - 27.06 * APR - 20.50 * MAY - 19.52 * NOV] + 10,035

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	SMITH 3	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Jun '14	
1.	EAF (%)	83.1	98.8	99.0	69.3	99.1	99.2	
2.	POF (%)	0.0	0.0	0.0	30.0	0.0	0.0	
3.	EUOF (%)	16.9	1.2	1.0	0.7	0.9	0.8	
4.	EUOR (%)	16.9	1.2	1.0	1.0	0.9	0.8	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	618.0	666.0	736.4	499.0	737.4	714.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	126.0	6.0	6.6	221.0	6.6	6.0	
9.	POH	0.0	0.0	0.0	216.0	0.0	0.0	
10.	FOH & EFOH	6.0	8.0	7.6	5.0	6.6	6.0	
11.	MOH & EMOH	120.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	2062340.0	2239628.0	2256418.0	1639682.0	2488223.0	2298113.0	
13.	Net Gen (MWH)	301423.6	327622.6	326449.4	239264.9	364147.9	334514.3	
14.	ANOHR (Btu/KWH)	6842.0	6836.0	6912.0	6853.0	6833.0	6870.0	
15.	NOF %	95.6	96.5	86.9	94.0	96.8	91.9	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [284.85 + 32.50 * JUL - 45.08 * OCT] + 6,495 - 0.00002 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2014 - December 2014

	SMITH 3	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Total
1.	EAF (%)	99.1	99.1	99.1	82.9	85.9	99.0	92.8
2.	POF (%)	0.0	0.0	0.0	16.1	13.3	0.0	4.9
3.	EUOF (%)	0.9	0.9	0.9	1.0	0.8	1.0	2.3
4.	EUOR (%)	0.9	0.9	0.9	1.1	1.0	1.0	2.4
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	737.4	737.4	713.6	617.0	620.0	737.3	8133.5
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	6.6	6.6	6.4	127.0	101.0	6.7	626.5
9.	POH	0.0	0.0	0.0	120.0	96.0	0.0	432.0
10.	FOH & EFOH	6.6	6.6	6.4	7.0	6.0	7.7	79.5
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	120.0
12.	Oper MBtu	2407779.0	2413733.0	2313907.0	1948716.0	1866106.0	2464018.0	26398663.0
13.	Net Gen (MWH)	347192.3	352061.4	337107.7	287548.5	269318.2	360236.6	3846887.4
14.	ANOHR (Btu/KWH)	6935.0	6856.0	6864.0	6777.0	6929.0	6840.0	6862.0
15.	NOF %	92.3	93.6	92.6	91.4	85.2	95.8	92.7
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [284.85 + 32.50 * JUL - 45.08 * OCT] + 6,495 - 0.00002 * LSRF / AKW

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Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2014 - December 2014

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 5	04/12/14	-	05/11/14	General boiler maintenance and inspection.
Crist 5	04/12/14	-	05/11/14	General boiler maintenance and inspection.
Crist 7	09/20/14	-	11/23/14	General boiler maintenance and inspection.
Smith 3	04/21/14	-	04/29/14	Hot gas path inspection
Smith 3	10/27/14	-	11/04/14	Borescope Inspection

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Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2014 - December 2014

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2014 - December 2014, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage
None		

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 46
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Penelope A. Rusk - PAR-1 (Composite)

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

INDEX

DOCUMENT NO.	TITLE	PAGE
1	Final Capacity Over/ (Under) Recovery For January 2012 - December 2012	11
2	Final Fuel and Purchased Power Over/ (Under) Recovery for January 2012 - December 2012	16
3	Actual Fuel and Purchased Power True-up *vs.* Original Estimates January 2012 - December 2012	18
4	Fuel and Purchased Power Cost Recovery YTD December 2012 Schedules A1, A2, A6 through A9 and A12	20

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER)RECOVERY FOR

JANUARY 2012 - DECEMBER 2012

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

1.	Actual End-of-Period True-up: Over/(Under) Recovery	($6,829,153)
2.	Less: Actual/Estimated Over/(Under) Recovery Per Order No. PSC-12-0664-FOF-EI For the January 2012 Through December 2012 Period	(6,702,505)
3.	Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2014 Through December 2014 Period	**($126,648)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Actual Jul-12	Actual Aug-12	Actual Sep-12	Actual Oct-12	Actual Nov-12	Actual Dec-12	Total
1 UNIT POWER CAPACITY CHARGES	1,707,079	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	1,706,393	20,477,402
2 CAPACITY PAYMENTS TO COGENERATORS	986,010	1,111,590	1,048,800	1,048,800	1,048,800	1,048,800	1,051,449	1,048,800	1,048,800	1,048,800	1,048,800	1,048,800	12,588,249
3 SCHEDULE J & D CAPACITY CHARGES	1,931,543	1,929,124	1,929,166	1,949,485	2,640,628	1,018,786	993,142	980,187	981,463	982,241	992,734	981,696	17,310,195
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (CAPACITY REVENUES)	(197,099)	(93,607)	(175,880)	(197,080)	(53,682)	(131,087)	(112,710)	(452,264)	(328,382)	(289,655)	(86,255)	(66,733)	(2,184,434)
6 TOTAL CAPACITY DOLLARS	4,427,533	4,653,500	4,508,479	4,507,598	5,342,139	3,642,892	3,638,274	3,283,116	3,408,274	3,447,779	3,661,672	3,670,156	48,191,412
7 JURISDICTIONAL PERCENTAGE	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
8 JURISDICTIONAL CAPACITY DOLLARS	4,409,005	4,634,026	4,489,612	4,488,735	5,319,783	3,627,647	3,623,048	3,269,377	3,394,012	3,433,350	3,646,349	3,654,797	47,989,741
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	3,280,531	3,077,047	3,066,026	3,400,481	3,582,502	4,028,216	4,098,617	4,217,932	4,235,262	3,802,490	3,172,211	2,948,008	42,909,323
10 PRIOR PERIOD TRUE-UP PROVISION	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,799)	(35,794)	(429,583)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,244,732	3,041,248	3,030,227	3,364,682	3,546,703	3,992,417	4,062,818	4,182,133	4,199,463	3,766,691	3,136,412	2,912,214	42,479,740
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(1,164,273)	(1,592,778)	(1,459,385)	(1,124,053)	(1,773,080)	364,770	439,770	912,756	805,451	333,341	(509,937)	(742,583)	(5,510,001)
13 INTEREST PROVISION FOR PERIOD	(138)	(365)	(411)	(576)	(781)	(848)	(804)	(880)	(579)	(525)	(765)	(583)	(7,255)
14 OTHER ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(1,741,480)	(2,870,092)	(4,427,436)	(5,851,433)	(6,940,263)	(8,678,325)	(8,278,604)	(7,803,839)	(6,856,164)	(6,015,493)	(5,646,878)	(6,121,781)	(1,741,480)
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	35,799	35,799	35,799	35,799	35,799	35,799	35,799	35,799	35,799	35,799	35,799	35,794	429,583
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(2,870,092)	(4,427,436)	(5,851,433)	(6,940,263)	(8,678,325)	(8,278,604)	(7,803,839)	(6,856,164)	(6,015,493)	(5,646,878)	(6,121,781)	(6,829,153)	**(6,829,153)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Actual Jul-12	Actual Aug-12	Actual Sep-12	Actual Oct-12	Actual Nov-12	Actual Dec-12	Total
1 BEGINNING TRUE-UP AMOUNT	(1,741,480)	(2,870,092)	(4,427,436)	(5,851,433)	(6,940,263)	(8,678,325)	(8,278,604)	(7,803,839)	(6,856,164)	(6,015,493)	(5,646,878)	(6,121,781)	(1,741,480)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(2,869,954)	(4,427,071)	(5,851,022)	(6,939,687)	(8,677,544)	(8,277,756)	(7,803,035)	(6,855,284)	(6,014,914)	(5,646,353)	(6,121,016)	(6,828,570)	(6,821,898)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(4,611,434)	(7,297,163)	(10,278,458)	(12,791,120)	(15,617,807)	(16,956,081)	(16,081,639)	(14,659,123)	(12,871,078)	(11,661,846)	(11,767,894)	(12,950,351)	(8,563,378)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,305,717)	(3,648,582)	(5,139,229)	(6,395,560)	(7,808,904)	(8,478,041)	(8,040,820)	(7,329,562)	(6,435,539)	(5,830,923)	(5,883,947)	(6,475,176)	(4,281,689)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.030	0.120	0.110	0.090	0.120	0.130	0.100	0.150	0.140	0.070	0.140	0.160	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.120	0.110	0.090	0.120	0.130	0.100	0.150	0.140	0.070	0.140	0.160	0.050	NA
7 TOTAL (LINE 5 + LINE 6)	0.150	0.230	0.200	0.210	0.250	0.230	0.250	0.290	0.210	0.210	0.300	0.210	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.075	0.115	0.100	0.105	0.125	0.115	0.125	0.145	0.105	0.105	0.150	0.105	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.006	0.010	0.008	0.009	0.010	0.010	0.010	0.012	0.009	0.009	0.013	0.009	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(138)	(365)	(411)	(576)	(781)	(848)	(804)	(880)	(579)	(525)	(765)	(583)	(7,255)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	$20,477,402	$37,669,076	($17,191,674)	-45.64%
2 CAPACITY PAYMENTS TO COGENERATORS	12,588,249	12,585,600	2,649	0.02%
3 SCHEDULE J & D CAPACITY CHARGES	17,310,195	0	17,310,195	0.00%
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0.00%
5 (CAPACITY REVENUES)	(2,184,434)	(1,696,872)	(487,562)	28.73%
6 TOTAL CAPACITY DOLLARS	$48,191,412	$48,557,804	($366,392)	-0.75%
7 JURISDICTIONAL PERCENTAGE	99.58152%	99.58152%	0.00000%	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$47,989,741	$48,354,600	($364,859)	-0.75%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	42,909,323	43,407,371	(498,048)	-1.15%
10 PRIOR PERIOD TRUE-UP PROVISION	(429,583)	(429,583)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$42,479,740	$42,977,788	($498,048)	-1.16%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($5,510,001)	($5,376,812)	($133,189)	2.48%
13 INTEREST PROVISION FOR PERIOD	(7,255)	(13,796)	6,541	-47.41%
14 OTHER ADJUSTMENT	0	0	0	0.00%
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(1,741,480)	(1,741,480)	0	0.00%
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	429,583	429,583	0	0.00%
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	($6,829,153)	($6,702,505)	($126,648)	1.89%

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER)RECOVERY

FOR

JANUARY 2012 - DECEMBER 2012

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2012 THROUGH DECEMBER 2012

1 TOTAL FUEL COSTS FOR THE PERIOD	$753,972,194
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	752,733,796
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	811,003,530
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	58,269,734
5 ADJUSTMENTS (INCL REVENUE REFUND TRUE-UP ADJUSTMENT)	41
6 INTEREST	67,975
7 TRUE-UP COLLECTED	(47,813,410)
8 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/11)	59,698,589
9 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7 + LINE 8)	70,222,929
10 PROJECTED OVER-RECOVERY PER PROJECTION FILED 8/31/12 (SCHEDULE E1-A LINE 3)	69,319,858
11 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 9 - LINE 10)	**$903,071**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2012 - DECEMBER 2012

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2012 THROUGH DECEMBER 2012

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$705,747,027	$800,026,687	($94,279,660)	(11.8)
	2. FUEL COST OF POWER SOLD	6,680,320	7,414,883	(734,563)	(9.9)
	2a. GAINS FROM MARKET BASED SALES	246,932	688,887	(441,955)	(64.2)
	3. FUEL COST OF PURCHASED POWER	39,192,153	18,485,740	20,706,413	112.0
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	7,751,242	11,459,630	(3,708,388)	(32.4)
	4. ENERGY COST OF ECONOMY PURCHASES	8,209,024	20,741,040	(12,532,016)	(60.4)
	6a. ADJ. TO FUEL COST (WAUCHULA)	0	0	0	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. SUM OF LINES A1 THRU 6a	$753,972,194	$842,609,327	($88,637,133)	(10.5)
C	1. JURISDICTIONAL FUEL REVENUE	$765,244,816	$796,133,646	($30,888,830)	(3.9)
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	$0	0	0.0
	2a. TRUE-UP PROVISION	47,813,410	$47,813,410	0	0.0
	2b. INCENTIVE PROVISION	(2,054,696)	($2,054,696)	0	0.0
	2c. ADJUSTMENT	0	0	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2c)	811,003,530	841,892,360	(30,888,830)	(3.7)
	6d.JURISD. TOTAL FUEL & NET PWR. TRANS.	752,733,796	841,805,228	(89,071,432)	(10.6)
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6d)	58,269,734	87,132	58,182,602	66,775.2
	7a. ADJUSTMENTS (INCL REVENUE REFUND TRUE-UP ADJ)	41	0	41	0.0
	8. INTEREST PROVISION - THIS PERIOD	67,975	53,773	14,202	26.4
	8a. TOTAL TRUE-UP AMOUNT FOR PERIOD (LINE 7 through 8)	$58,337,750	$140,905	$58,196,845	41,302.2
	9.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2012)	59,698,589	47,813,410	11,885,179	24.9
	10.TRUE-UP COLLECTED (REFUNDED)	(47,813,410)	(47,813,410)	0	0.0
	11.END OF PERIOD TOTAL NET TRUE-UP (LINE C8a through C10)	$70,222,929	$140,905	$70,082,024	49,737.1

Line numbers reference Schedule A-2 included in Document No. 4

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY

YTD DECEMBER 2012

SCHEDULES A1 AND A2

AND

SCHEDULES A6 THROUGH A9

AND

SCHEDULE A12

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 AND A2

DECEMBER 2012

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: December 2012

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	51,558,792	63,949,621	(12,390,829)	-19.4%	1,305,561	1,503,670	(198,109)	-13.2%	3.94917	4.25290	(0.30374)	-7.1%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adjustments to Fuel Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4b)	**51,558,792**	**63,949,621**	**(12,390,829)**	**-19.4%**	**1,305,561**	**1,503,670**	**(198,109)**	**-13.2%**	**3.94917**	**4.25290**	**(0.30374)**	**-7.1%**
6. Fuel Cost of Purchased Power - Firm (A7)	2,341,228	388,280	1,952,948	503.0%	68,799	6,110	62,689	1026.0%	3.40300	6.35483	(2.95183)	-46.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	341,842	308,170	33,672	10.9%	9,426	6,970	2,456	35.2%	3.62659	4.42138	(0.79479)	-18.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	838,641	928,850	(90,209)	-9.7%	28,658	18,530	10,128	54.7%	2.92638	5.01268	(2.08631)	-41.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**3,521,711**	**1,625,300**	**1,896,411**	**116.7%**	**106,883**	**31,610**	**75,273**	**238.1%**	**3.29492**	**5.14173**	**(1.84681)**	**-35.9%**
13. TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					**1,412,444**	**1,535,280**	**(122,836)**	**-8.0%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	36,255	29,750	6,505	21.9%	1,413	740	673	90.9%	2.56582	4.02027	(1.45445)	-36.2%
15. Fuel Cost of Sch. D Sep. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. C/CB Sales (A6)	73,336	0	73,336	0.0%	3,022	0	3,022	0.0%	2.42674	0.00000	2.42674	0.0%
17. Fuel Cost of OATT Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	15,367	776,877	(761,510)	-98.0%	594	19,470	(18,876)	-96.9%	2.58704	3.99012	(1.40309)	-35.2%
19. Gains on Sales	2,723	77,773	(75,050)	-96.5%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**127,681**	**884,400**	**(756,719)**	**-85.6%**	**5,029**	**20,210**	**(15,181)**	**-75.1%**	**2.53889**	**4.37605**	**(1.83716)**	**-42.0%**
21. Net Inadvertant Interchange					141	0	141	0.0%				
22. Wheeling Rec'd. less Wheeling Delv'd.					3,705	0	3,705	0.0%				
23. Interchange and Wheeling Losses					3,607	0	3,607	0.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**54,952,822**	**64,690,521**	**(9,737,699)**	**-15.1%**	**1,407,654**	**1,515,070**	**(107,416)**	**-7.1%**	**3.90386**	**4.26980**	**(0.36595)**	**-8.6%**
25. Net Unbilled	2,048,979 (a)	408,407 (a)	1,640,572	401.7%	52,486	9,565	42,921	448.7%	3.90386	4.26981	(0.36595)	-8.6%
26. Company Use	97,848 (a)	128,094 (a)	(30,246)	-23.6%	2,506	3,000	(494)	-16.5%	3.90384	4.26980	(0.36596)	-8.6%
27. T & D Losses	2,845,484 (a)	3,118,195 (a)	(272,711)	-8.7%	72,889	73,029	(140)	-0.2%	3.90386	4.26980	(0.36595)	-8.6%
28. System MWH Sales	54,952,822	64,690,521	(9,737,699)	-15.1%	1,279,773	1,429,476	(149,703)	-10.5%	4.29395	4.52547	(0.23152)	-5.1%
29. Wholesale MWH Sales	(115,933)	(1,766)	(114,167)	6464.7%	(2,700)	(39)	(2,661)	6823.1%	4.29381	4.52821	(0.23439)	-5.2%
30. Jurisdictional MWH Sales	54,836,889	64,688,755	(9,851,866)	-15.2%	1,277,073	1,429,437	(152,364)	-10.7%	4.29395	4.52547	(0.23152)	-5.1%
31. Jurisdictional Loss Multiplier									1.00010	1.00010	0.00000	0.0%
32. Jurisdictional MWH Sales Adjusted for Line Losses	54,842,373	64,695,224	(9,852,851)	-15.2%	1,277,073	1,429,437	(152,364)	-10.7%	4.29438	4.52592	(0.23154)	-5.1%
33. Other	0	0	0	0.0%	1,277,073	1,429,437	(152,364)	-10.7%	0.00000	0.00000	0.00000	0.0%
34. True-up *	(3,984,449)	(3,984,449)	0	0.0%	1,277,073	1,429,437	(152,364)	-10.7%	(0.31200)	(0.27874)	(0.03326)	11.9%
35. Total Jurisdictional Fuel Cost (Excl. GPIF)	50,857,924	60,710,775	(9,852,851)	-16.2%	1,277,073	1,429,437	(152,364)	-10.7%	3.98238	4.24718	(0.26480)	-6.2%
36. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
37. Fuel Cost Adjusted for Taxes (Excl. GPIF)	50,894,542	60,754,487	(9,859,945)	-16.2%	1,277,073	1,429,437	(152,364)	-10.7%	3.98525	4.25024	(0.26499)	-6.2%
38. GPIF * (Already Adjusted for Taxes)	171,221	171,221	0	0.0%	1,277,073	1,429,437	(152,364)	-10.7%	0.01341	0.01198	0.00143	11.9%
39. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**51,065,763**	**60,925,708**	**(9,859,945)**	**-16.2%**	**1,277,073**	**1,429,437**	**(152,364)**	**-10.7%**	**3.99866**	**4.26222**	**(0.26356)**	**-6.2%**
40. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.999**	**4.262**	**(0.263)**	**-6.2%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: December 2012

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	705,747,027	800,026,687	(94,279,660)	-11.8%	18,278,666	19,243,810	(965,144)	-5.0%	3.86104	4.15732	(0.29628)	-7.1%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adjustments to Fuel Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments to Fuel Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4b)	**705,747,027**	**800,026,687**	**(94,279,660)**	**-11.8%**	**18,278,666**	**19,243,810**	**(965,144)**	**-5.0%**	**3.86104**	**4.15732**	**(0.29628)**	**-7.1%**
6. Fuel Cost of Purchased Power - Firm (A7)	39,192,153	18,485,740	20,706,413	112.0%	702,843	318,850	383,993	120.4%	5.57623	5.79763	(0.22140)	-3.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	8,209,024	20,741,040	(12,532,016)	-60.4%	259,780	480,000	(220,220)	-45.9%	3.15999	4.32105	(1.16106)	-26.9%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	7,751,242	11,459,630	(3,708,388)	-32.4%	271,036	224,630	46,406	20.7%	2.85986	5.10156	(2.24170)	-43.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**55,152,419**	**50,686,410**	**4,466,009**	**8.8%**	**1,233,659**	**1,023,480**	**210,179**	**20.5%**	**4.47064**	**4.95236**	**(0.48172)**	**-9.7%**
13. TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					**19,512,325**	**20,267,290**	**(754,965)**	**-3.7%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	445,404	533,570	(88,166)	-16.5%	18,202	13,720	4,482	32.7%	2.44701	3.88899	(1.44199)	-37.1%
15. Fuel Cost of Sch. D Sep. Sales (A6)	1,436,097	0	1,436,097	0.0%	37,300	0	37,300	0.0%	3.85013	0.00000	3.85013	0.0%
16. Fuel Cost of Sch. C/CB Sales (A6)	3,942,376	0	3,942,376	0.0%	141,554	0	141,554	0.0%	2.78507	0.00000	2.78507	0.0%
17. Fuel Cost of OATT Sales (A6)	112,518	0	112,518	0.0%	3,911	0	3,911	0.0%	2.87696	0.00000	2.87696	0.0%
18. Fuel Cost of Market Base Sales (A6)	743,925	6,881,313	(6,137,388)	-89.2%	34,129 *	175,000	(140,871)	-80.5%	2.17974	3.93218	(1.75243)	-44.6%
19. Gains on Sales	246,932	688,887	(441,955)	-64.2%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**6,927,252**	**8,103,770**	**(1,176,518)**	**-14.5%**	**235,096**	**188,720**	**46,376**	**24.6%**	**2.94656**	**4.29407**	**(1.34751)**	**-31.4%**
21. Net Inadvertant Interchange					554	0	554	0.0%				
22. Wheeling Rec'd. less Wheeling Delv'd.					44,432	0	44,432	0.0%				
23. Interchange and Wheeling Losses					47,798	0	47,798	0.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**753,972,194**	**842,609,327**	**(88,637,133)**	**-10.5%**	**19,274,417**	**20,078,570**	**(804,153)**	**-4.0%**	**3.91178**	**4.19656**	**(0.28478)**	**-6.8%**
25. Net Unbilled	(2,550,151) (a)	725,199 (a)	(3,275,350)	-451.6%	(31,887)	24,638	(56,525)	-229.4%	7.99746	2.94342	5.05405	171.7%
26. Company Use	1,281,615 (a)	1,512,512 (a)	(230,897)	-15.3%	32,630	36,000	(3,370)	-9.4%	3.92767	4.20142	(0.27376)	-6.5%
27. T & D Losses	32,509,426 (a)	40,109,550 (a)	(7,600,124)	-18.9%	833,128	953,710	(120,582)	-12.6%	3.90209	4.20563	(0.30354)	-7.2%
28. System MWH Sales	753,972,194	842,609,327	(88,637,133)	-10.5%	18,440,546	19,064,222	(623,676)	-3.3%	4.08867	4.41985	(0.33118)	-7.5%
29. Wholesale MWH Sales	(1,313,663)	(888,271)	(425,392)	47.9%	(31,965)	(19,969)	(11,996)	60.1%	4.10969	4.44825	(0.33856)	-7.6%
30. Jurisdictional MWH Sales	752,658,531	841,721,056	(89,062,525)	-10.6%	18,408,581	19,044,253	(635,672)	-3.3%	4.08863	4.41982	(0.33119)	-7.5%
31. Jurisdictional Loss Multiplier									1.00010	1.00010	0.00000	0.0%
32. Jurisdictional MWH Sales Adjusted for Line Losses	752,733,796	841,805,228	(89,071,432)	-10.6%	18,408,581	19,044,253	(635,672)	-3.3%	4.08904	4.42026	(0.33122)	-7.5%
33. Other	0	0	0	0.0%	18,408,581	19,044,253	(635,672)	-3.3%	0.00000	0.00000	0.00000	0.0%
34. True-up *	(47,813,410)	(47,813,410)	0	0.0%	18,408,581	19,044,253	(635,672)	-3.3%	(0.25973)	(0.25106)	(0.00867)	3.5%
35. Total Jurisdictional Fuel Cost (Excl. GPIF)	704,920,386	793,991,818	(89,071,432)	-11.2%	18,408,581	19,044,253	(635,672)	-3.3%	3.82930	4.16919	(0.33989)	-8.2%
36. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
37. Fuel Cost Adjusted for Taxes (Excl. GPIF)	705,427,929	794,563,493	(89,135,564)	-11.2%	18,408,581	19,044,253	(635,672)	-3.3%	3.83206	4.17220	(0.34014)	-8.2%
38. GPIF * (Already Adjusted for Taxes)	2,054,696	2,054,696	0	0.0%	18,408,581	19,044,253	(635,672)	-3.3%	0.01116	0.01079	0.00037	3.5%
39. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**707,482,625**	**796,618,189**	**(89,135,564)**	**-11.2%**	**18,408,581**	**19,044,253**	**(635,672)**	**-3.3%**	**3.84322**	**4.18299**	**(0.33977)**	**-8.1%**
40. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.843**	**4.183**	**(0.340)**	**-8.1%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2012

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	51,558,792	63,949,621	(12,390,829)	-19.4%	705,747,027	800,026,687	(94,279,660)	-11.8%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	124,958	806,627	(681,669)	-84.5%	6,680,320	7,414,883	(734,563)	-9.9%
2a. GAINS FROM SALES	2,723	77,773	(75,050)	-96.5%	246,932	688,887	(441,955)	-64.2%
3. FUEL COST OF PURCHASED POWER	2,341,228	388,280	1,952,948	503.0%	39,192,153	18,485,740	20,706,413	112.0%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	838,641	928,850	(90,209)	-9.7%	7,751,242	11,459,630	(3,708,388)	-32.4%
4. ENERGY COST OF ECONOMY PURCHASES	341,842	308,170	33,672	10.9%	8,209,024	20,741,040	(12,532,016)	-60.4%
5. TOTAL FUEL & NET POWER TRANSACTION	54,952,822	64,690,521	(9,737,699)	-15.1%	753,972,194	842,609,327	(88,637,133)	-10.5%
6a. ADJUSTMENTS TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	54,952,822	64,690,521	(9,737,699)	-15.1%	753,972,194	842,609,327	(88,637,133)	-10.5%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,277,073	1,429,437	(152,364)	-10.7%	18,408,581	19,044,253	(635,672)	-3.3%
2. NONJURISDICTIONAL SALES	2,700	39	2,661	6823.1%	31,965	19,969	11,996	60.1%
3. TOTAL SALES	1,279,773	1,429,476	(149,703)	-10.5%	18,440,546	19,064,222	(623,676)	-3.3%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9978903	0.9999727	(0.0020824)	-0.2%	0.9982666	0.9989525	(0.0006859)	-0.1%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2012

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	52,352,440	59,188,939	(6,836,499)	-11.6%	765,244,816	796,133,646	(30,888,830)	-3.9%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	3,984,449	3,984,449	0	0.0%	47,813,410	47,813,410	0	0.0%
2b. INCENTIVE PROVISION	(171,221)	(171,221)	0	0.0%	(2,054,696)	(2,054,696)	0	0.0%
2c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	56,165,668	63,002,167	(6,836,499)	-10.9%	811,003,530	841,892,360	(30,888,830)	-3.7%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	54,952,822	64,690,521	(9,737,699)	-15.1%	753,972,194	842,609,327	(88,637,133)	-10.5%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9978903	0.9999727	(0.0020824)	-0.2%	-	-	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	54,836,889	64,688,755	(9,851,866)	-15.2%	752,658,531	841,721,056	(89,062,525)	-10.6%
6a. JURISDIC. LOSS MULTIPLIER	1.00010	1.00010	0.00000	0.0%	-	-	-	0.0%
6b. (LINE C6 x LINE C6a)	54,842,373	64,695,224	(9,852,851)	-15.2%	752,733,796	841,805,228	(89,071,432)	-10.6%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	54,842,373	64,695,224	(9,852,851)	-15.2%	752,733,796	841,805,228	(89,071,432)	-10.6%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	1,323,295	(1,693,057)	3,016,352	-178.2%	58,269,734	87,132	58,182,602	66775.2%
7a. REVENUE REFUND TRUE-UP ADJUSTMENT	0	0	0	0.0%	41	0	41	0.0%
8. INTEREST PROVISION FOR THE MONTH	6,439	566	5,873	1037.6%	67,975	53,773	14,202	26.4%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	72,877,644	5,817,845	67,059,799	1152.7%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(3,984,449)	(3,984,449)	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	70,222,929	140,905	70,082,024	49737.1%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2012

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C7a + C9)	72,877,644	5,817,845	67,059,799	1152.7%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C7a + C9 + C10)	70,216,490	140,339	70,076,151	49933.5%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	143,094,134	5,958,184	137,135,950	2301.6%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	71,547,067	2,979,092	68,567,975	2301.6%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	0.160	0.230	(0.070)	-30.4%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	0.050	0.230	(0.180)	-78.3%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	0.210	0.460	(0.250)	-54.3%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	0.105	0.230	(0.125)	-54.3%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.009	0.019	(0.010)	-52.6%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	6,439	566	5,873	1037.6%	----------NOT APPLICABLE----------			

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2012 - DECEMBER 2012

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
SEMINOLE ELEC. CO-OP	JURISDIC.	SCH. - D	13,720.0	0.0	13,720.0	3.889	3.889	533,570.00	533,570.00	0.00
VARIOUS	JURISDIC.	MKT.BASE	175,000.0	0.0	175,000.0	3.932	4.724	6,881,313.00	8,266,710.00	688,887.00
TOTAL			**188,720.0**	**0.0**	**188,720.0**	**3.929**	**4.663**	**7,414,883.00**	**8,800,280.00**	**688,887.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	5,483.0	0.0	5,483.0	2.485	2.733	136,225.51	149,848.07	406.57
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	12,719.8	0.0	12,719.8	2.431	2.674	309,179.76	340,097.73	5,213.17
FLORIDA POWER & LIGHT	SEP.	SCH. - D	37,300.0	0.0	37,300.0	3.850	4.378	1,436,097.00	1,633,041.00	0.00
FLORIDA POWER & LIGHT		SCH. - C	322.0	0.0	322.0	2.441	3.570	7,858.74	11,495.83	3,181.66
PROGRESS ENERGY FLORIDA		SCH. - C	163.0	0.0	163.0	2.268	3.396	3,697.07	5,535.72	1,597.27
ORLANDO UTILITIES COMMISSION		SCH. - C	688.0	0.0	688.0	1.796	2.295	12,355.91	15,792.37	3,020.36
THE ENERGY AUTHORITY		SCH. - C	91.0	0.0	91.0	2.103	2.660	1,914.12	2,420.84	410.83
CITY OF HOMESTEAD		SCH. - C	78.0	0.0	78.0	2.430	3.078	1,895.12	2,400.66	429.13
PROGRESS ENERGY FLORIDA		SCH. - CB	10,475.0	0.0	10,475.0	3.066	3.302	321,122.92	345,899.18	3,782.26
FLORIDA POWER & LIGHT		SCH. - CB	56,217.0	0.0	56,217.0	3.280	3.487	1,844,165.63	1,960,507.67	15,113.75
REEDY CREEK		SCH. - CB	62,158.0	0.0	62,158.0	2.359	2.551	1,466,545.74	1,585,671.31	(131.29)
ORLANDO UTILITIES COMMISSION		SCH. - CB	2,285.0	0.0	2,285.0	3.137	3.242	71,677.23	74,074.93	0.00
SEMINOLE ELECTRIC		SCH. - CB	5,840.0	0.0	5,840.0	2.379	2.563	138,915.02	149,702.20	0.00
THE ENERGY AUTHORITY		SCH. - CB	3,237.0	0.0	3,237.0	2.231	2.377	72,227.87	76,948.95	0.00
CARGILL ALLIANT		SCH. - MA	172.0	0.0	172.0	1.866	2.403	3,210.18	4,133.09	869.45
CONSTELLATION COMMODITIES		SCH. - MA	3,731.0	0.0	3,731.0	1.710	2.229	63,809.85	83,180.04	17,028.66
FLORIDA POWER & LIGHT		SCH. - MA	1,241.0	0.0	1,241.0	3.582	4.300	44,452.62	53,363.00	8,910.38
NEW SMYRNA BEACH		SCH. - MA	3,029.0	0.0	3,029.0	2.377	3.205	72,007.51	97,084.48	21,981.12
REEDY CREEK		SCH. - MA	165.0	0.0	165.0	3.285	3.538	5,420.00	5,836.90	416.90
SEMINOLE ELECTRIC		SCH. - MA	40.0	0.0	40.0	1.893	2.480	757.09	992.16	213.87
CITY OF TALLAHASSEE		SCH. - MA	1,750.0	0.0	1,750.0	3.082	4.306	53,930.76	75,346.25	17,156.99
SOUTHERN COMPANY		SCH. - MA	2,055.0	0.0	2,055.0	2.456	2.745	50,468.99	56,412.64	3,876.50
THE ENERGY AUTHORITY		SCH. - MA	10,343.0	0.0	10,343.0	1.876	2.492	194,073.01	257,707.35	51,363.92
EDF TRADING		SCH. - MA	4,149.0	0.0	4,149.0	2.147	3.240	89,066.51	134,412.65	41,404.16
JP MORGAN VENTURES		SCH. - MA	3,125.0	0.0	3,125.0	2.698	3.501	84,302.59	109,421.51	24,239.13
MORGAN STANLEY		SCH. - MA	4,205.0	0.0	4,205.0	1.881	2.592	79,100.97	109,014.15	25,559.93
CITY OF HOMESTEAD		SCH. - MA	124.0	0.0	124.0	2.681	3.636	3,324.13	4,508.86	886.88
SEMINOLE ELECTRIC		OATT	3,911.0	0.0	3,911.0	2.877	2.877	112,517.76	112,517.76	0.00
SUB-TOTAL			**235,096.8**	**0.0**	**235,096.8**	**2.842**	**3.172**	**6,680,319.61**	**7,457,367.30**	**246,931.60**
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			18,202.8	0.0	18,202.8	2.447	2.692	445,405.27	489,945.80	5,619.74
SUB-TOTAL SCHEDULE D POWER SALES-SEP.			37,300.0	0.0	37,300.0	3.850	4.378	1,436,097.00	1,633,041.00	0.00
SUB-TOTAL SCHEDULE C POWER SALES			1,342.0	0.0	1,342.0	2.066	2.805	27,720.96	37,645.42	8,639.25
SUB-TOTAL SCHEDULE CB POWER SALES			140,212.0	0.0	140,212.0	2.792	2.990	3,914,654.41	4,192,804.24	18,764.72
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			34,129.0	0.0	34,129.0	2.180	2.905	743,924.21	991,413.08	213,907.89
SUB-TOTAL OATT POWER SALES			3,911.0	0.0	3,911.0	2.877	2.877	112,517.76	112,517.76	0.00
TOTAL			**235,096.8**	**0.0**	**235,096.8**	**2.842**	**3.172**	**6,680,319.61**	**7,457,367.30**	**246,931.60**
DIFFERENCE			46,376.8	0.0	46,376.8	(1.087)	(1.491)	(734,563.39)	(1,342,912.70)	(441,955.40)
DIFFERENCE %			24.6%	0.0%	24.6%	-27.7%	-32.0%	-9.9%	-15.3%	-64.2%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012.

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2012 - DECEMBER 2012

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
HARDEE POWER PARTNERS	IPP	216,820.0	0.0	0.0	216,820.0	5.714	5.714	12,388,290.00
RELIANT	SCH. - D	530.0	0.0	0.0	530.0	6.342	6.342	33,610.00
PASCO COGEN	SCH. - D	101,500.0	0.0	0.0	101,500.0	5.974	5.974	6,063,840.00
TOTAL		**318,850.0**	**0.0**	**0.0**	**318,850.0**	**5.798**	**5.798**	**18,485,740.00**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	382,824.0	0.0	0.0	382,824.0	6.836	6.836	26,171,689.01
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CALPINE	SCH. - D	23,211.0	0.0	0.0	23,211.0	5.079	5.079	1,178,981.76
PASCO COGEN	SCH. - D	252,015.0	0.0	0.0	252,015.0	4.045	4.045	10,193,137.42
RELIANT	SCH. - D	31,133.0	0.0	0.0	31,133.0	4.127	4.127	1,284,916.55
CALPINE	OATT	13,660.0	0.0	0.0	13,660.0	2.661	2.661	363,428.02
SUB-TOTAL		**702,843.0**	**0.0**	**0.0**	**702,843.0**	**5.576**	**5.576**	**39,192,152.76**
SUB-TOTAL SCHEDULE IPP PURCHASED POWER		382,824.0	0.0	0.0	382,824.0	6.836	6.836	26,171,689.01
SUB-TOTAL SCHEDULE D PURCHASED POWER		306,359.0	0.0	0.0	306,359.0	4.131	4.131	12,657,035.73
SUB-TOTAL SCHEDULE OATT PURCHASED POWER		13,660.0	0.0	0.0	13,660.0	2.661	2.661	363,428.02
TOTAL		**702,843.0**	**0.0**	**0.0**	**702,843.0**	**5.576**	**5.576**	**39,192,152.76**
DIFFERENCE		383,993.0	0.0	0.0	383,993.0	(0.222)	(0.222)	20,706,412.76
DIFFERENCE %		120.4%	0.0%	0.0%	120.4%	-3.8%	-3.8%	112.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2012 - DECEMBER 2012

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7) CENTS/KWH		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FROM OTHER UTILITIES	MWH FOR INTER-RUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	**COGEN.**							
	FIRM	72,960.0	0.0	0.0	72,960.0	3.491	3.491	2,547,370.00
	AS AVAIL.	151,670.0	0.0	0.0	151,670.0	5.876	5.876	8,912,260.00
TOTAL		**224,630.0**	**0.0**	**0.0**	**224,630.0**	**5.102**	**5.102**	**11,459,630.00**
ACTUAL:								
	FIRM							
ORANGE COGENERATION L.P.	COGEN.	75,927.0	0.0	0.0	75,927.0	2.686	2.686	2,039,472.73
	AS AVAILABLE							
McKAY BAY REFUSE	COGEN.	4,629.0	0.0	0.0	4,629.0	3.004	3.004	139,059.35
CARGILL RIDGEWOOD	COGEN.	26,658.0	0.0	0.0	26,658.0	2.962	2.962	789,558.18
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	72,241.0	0.0	0.0	72,241.0	2.926	2.926	2,113,939.84
CF INDUSTRIES INC.	COGEN.	3,925.0	0.0	0.0	3,925.0	2.922	2.922	114,678.58
IMC-AGRICO-NEW WALES	COGEN.	14,303.0	0.0	0.0	14,303.0	2.934	2.934	419,631.16
IMC-AGRICO-S. PIERCE	COGEN.	72,859.0	0.0	0.0	72,859.0	2.910	2.910	2,120,463.73
AUBURNDALE POWER PARTNERS	COGEN.	488.0	0.0	0.0	488.0	2.922	2.922	14,259.70
HILLSBOROUGH COUNTY	COGEN.	6.0	0.0	0.0	6.0	2.990	2.990	179.40
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR FIRM		**75,927.0**	**0.0**	**0.0**	**75,927.0**	**2.686**	**2.686**	**2,039,472.73**
SUB-TOTAL FOR AS AVAIL.		**195,109.0**	**0.0**	**0.0**	**195,109.0**	**2.927**	**2.927**	**5,711,769.94**
TOTAL		**271,036.0**	**0.0**	**0.0**	**271,036.0**	**2.860**	**2.860**	**7,751,242.67**
DIFFERENCE		46,406.0	0.0	0.0	46,406.0	(2.242)	(2.242)	(3,708,387.33)
DIFFERENCE %		20.7%	0.0%	0.0%	20.7%	-43.9%	-43.9%	-32.4%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2012 - DECEMBER 2012

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) COST IF GENERATED		(9)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACTION COSTS CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT (5) X (6)	(A) CENTS PER KWH	(B) TOTAL COST	FUEL SAVINGS (8B)-6
ESTIMATED:									
VARIOUS	Economy	480,000.0	0.0	480,000.0	4.321	20,741,040.00	4.321	20,741,040.00	0.00
TOTAL		**480,000.0**	**0.0**	**480,000.0**	**4.321**	**20,741,040.00**	**4.321**	**20,741,040.00**	**0.00**
ACTUAL:									
OKEELANTA	SCH. - REB	594.0	0.0	594.0	3.718	22,087.00	4.456	26,470.83	4,383.83
FLA. POWER & LIGHT	SCH. - C	849.0	0.0	849.0	2.655	22,537.13	4.069	34,548.16	12,011.03
THE ENERGY AUTHORITY	SCH. - C	48.0	0.0	48.0	5.267	2,528.16	7.855	3,770.40	1,242.24
SEMINOLE ELEC. CO-OP	SCH. - C	48.0	0.0	48.0	9.855	4,730.40	15.000	7,200.00	2,469.60
PROGRESS ENERGY FLORIDA	SCH. - J	2,855.0	0.0	2,855.0	3.006	85,821.86	3.619	103,318.29	17,496.43
EAGLE ENERGY(EDF)	SCH. - J	5,998.0	0.0	5,998.0	2.874	172,410.50	3.482	208,840.29	36,429.79
FLA. POWER & LIGHT	SCH. - J	14,100.0	0.0	14,100.0	3.517	495,880.00	4.222	595,241.10	99,361.10
CITY OF LAKELAND	SCH. - J	585.0	0.0	585.0	5.290	30,945.00	5.290	30,945.00	0.00
ORLANDO UTIL. COMM.	SCH. - J	3,895.0	0.0	3,895.0	4.959	193,165.00	5.637	219,580.05	26,415.05
THE ENERGY AUTHORITY	SCH. - J	3,857.0	0.0	3,857.0	4.116	158,758.00	4.913	189,494.58	30,736.58
CITY OF TALLAHASSEE	SCH. - J	1,405.0	0.0	1,405.0	2.183	30,670.00	2.819	39,605.05	8,935.05
CALPINE	SCH. - J	191,941.0	0.0	191,941.0	3.039	5,833,334.75	3.349	6,428,478.89	595,144.14
SEMINOLE ELEC. CO-OP	SCH. - J	6,547.0	0.0	6,547.0	4.050	265,155.00	5.271	345,106.39	79,951.39
J P MORGAN VENTURES	SCH. - J	8,180.0	0.0	8,180.0	3.161	258,571.00	4.054	331,613.38	73,042.38
MORGAN STANLEY	SCH. - J	1,629.0	0.0	1,629.0	3.306	53,855.00	3.961	64,528.24	10,673.24
CONSTELLATION COMMODITIES	SCH. - J	10,910.0	0.0	10,910.0	3.072	335,164.00	3.900	425,530.54	90,366.54
SOUTHERN COMPANY	SCH. - J	6,339.0	0.0	6,339.0	3.840	243,410.00	4.475	283,688.19	40,278.19
SUB-TOTAL		**259,780.0**	**0.0**	**259,780.0**	**3.160**	**8,209,022.80**	**3.595**	**9,337,959.38**	**1,128,936.58**
SUB-TOTAL SCHEDULE REB ECONOMY PURCHASES		594.0	0.0	594.0	3.718	22,087.00	4.456	26,470.83	4,383.83
SUB-TOTAL SCHEDULE C ECONOMY PURCHASES		945.0	0.0	945.0	3.153	29,795.69	4.817	45,518.56	15,722.87
SUB-TOTAL SCHEDULE J ECONOMY PURCHASES		258,241.0	0.0	258,241.0	3.159	8,157,140.11	3.588	9,265,969.99	1,108,829.88
TOTAL		**259,780.0**	**0.0**	**259,780.0**	**3.160**	**8,209,022.80**	**3.595**	**9,337,959.38**	**1,128,936.58**
DIFFERENCE		(220,220.0)	0.0	(220,220.0)	(1.161)	(12,532,017.20)	(0.726)	(11,403,080.62)	1,128,936.58
DIFFERENCE %		-45.9%	0.0%	-45.9%	-26.9%	-60.4%	-16.8%	-55.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2012 - DECEMBER 2012

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
ORANGE COGEN LP	4/17/1989	12/31/2015	QF	QF = QUALIFYING FACILITY
HARDEE POWER PARTNERS	1/1/1993	12/31/2012	LT	LT = LONG TERM
SEMINOLE ELECTRIC **	6/1/1992	12/31/2012	LT	ST = SHORT-TERM
CALPINE	11/1/2011	12/31/2016	LT	** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
RELIANT	1/1/2009	5/31/2012	LT	
PASCO COGEN LTD	1/1/2009	12/31/2018	LT	

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
HARDEE POWER PARTNERS	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
RELIANT	158.0	158.0	158.0	158.0	158.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PASCO COGEN LTD	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
SEMINOLE ELECTRIC	5.0	4.2	5.2	1.9	5.4	4.9	5.4	5.8	5.7	5.7	5.4	5.2

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	986,010	1,111,590	1,048,800	1,048,800	1,048,800	1,048,800	1,051,449	1,048,800	1,048,800	1,048,800	1,048,800	1,048,800	12,588,249
TOTAL COGENERATION	**$ 986,010**	**$ 1,111,590**	**$ 1,048,800**	**$ 1,048,800**	**$ 1,048,800**	**$ 1,048,800**	**$ 1,051,449**	**$ 1,048,800**	**$ 1,048,800**	**$ 1,048,800**	**$ 1,048,800**	**$ 1,048,800**	**$ 12,588,249**

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2012 THROUGH DECEMBER 2012

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
HARDEE POWER PARTNERS	[redacted]												
CALPINE - D													
RELIANT ENERGY SERVICES - D													
PASCO COGEN LTD - D													
CITY OF TALLAHASSEE													
SEMINOLE ELECTRIC													
FLORIDA POWER & LIGHT													
PROGRESS ENERGY FLORIDA													
THE ENERGY AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
PROGRESS ENERGY FLORIDA - CB													
FLORIDA POWER & LIGHT - CB													
ORLANDO UTILITIES - CB													
REEDY CREEK - CB													
SEMINOLE ELECTRIC - CB													
THE ENERGY AUTHORITY - CB													
CARGILL ALLIANT - MA													
CITY OF TALLAHASSEE - MA													
CONSTELLATION COMMODITIES - MA													
REEDY CREEK - MA													
SEMINOLE ELECTRIC - MA													
THE ENERGY AUTHORITY - MA													
J P MORGAN VENTURES - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
CITY OF HOMESTEAD - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	$ 3,441,523	$ 3,541,910	$ 3,459,679	$ 3,458,798	$ 4,293,339	$ 2,594,092	$ 2,586,825	$ 2,234,316	$ 2,359,475	$ 2,398,979	$ 2,612,872	$ 2,621,356	$ 35,603,164
TOTAL CAPACITY	$ 4,427,533	$ 4,653,500	$ 4,508,479	$ 4,507,598	$ 5,342,139	$ 3,642,892	$ 3,638,274	$ 3,283,116	$ 3,408,275	$ 3,447,779	$ 3,661,672	$ 3,670,156	$ 48,191,413

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

FUEL AND PURCHASED POWER COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2013 THROUGH DECEMBER 2013

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 47
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Penelope A. Rusk - PAR-2 (Composite)

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1-B Calculation of Estimated True-Up	(JAN. 2013 - DEC. 2013)
3	Schedule E2 Cost Recovery Clause Calculation	(")
4-5	Schedule E3 Generating System Comparative Data	(")
6-17	Schedule E4 System Net Generation and Fuel Cost	(")
18-19	Schedule E5 Inventory Analysis	(")
20-21	Schedule E6 Power Sold	(")
22-23	Schedule E7 Purchased Power	(")
24	Schedule E8 Energy Payment to Qualifying Facilities	(")
25	Schedule E9 Economy Energy Purchases	(")

TAMPA ELECTRIC COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	TOTAL
A. 1.	Fuel Cost of System Net Generation	47,575,217	41,797,777	49,807,915	51,106,017	61,597,686	66,624,726	70,420,741	72,990,974	69,210,960	63,676,461	52,778,546	54,153,417	701,740,437
2.	Fuel Cost of Power Sold [1]	57,983	204,612	940,848	1,273,814	1,289,151	628,996	411,387	394,287	411,957	455,687	430,357	559,428	7,058,507
3.	Fuel Cost of Purchased Power	869,784	604,599	93,248	156,018	171,977	1,118,884	1,656,270	1,133,340	1,640,920	848,780	603,610	195,540	9,092,970
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	851,284	575,496	564,698	550,239	527,434	759,243	623,667	631,372	621,053	633,498	626,871	617,893	7,582,748
4.	Energy Cost of Economy Purchases	1,659,542	1,329,876	485,984	5,026,104	2,810,164	925,277	747,690	344,302	784,969	556,235	440,858	613,034	15,724,035
5.	Polk 1 Conversion Depreciation & ROI	0	0	0	0	0	74,893	385,626	383,467	381,307	379,148	376,988	374,828	2,356,257
5a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**50,897,844**	**44,103,136**	**50,010,997**	**55,564,564**	**63,818,110**	**68,874,027**	**73,422,607**	**75,089,168**	**72,227,252**	**65,638,435**	**54,396,516**	**55,395,284**	**729,437,940**
[1]	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,393,882	1,280,888	1,309,195	1,383,298	1,466,195	1,696,252	1,788,485	1,783,316	1,824,748	1,629,257	1,387,039	1,359,771	18,302,326
2.	Non-Jurisdictional MWH Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**TOTAL SALES (LINE B1+B2)**	**1,393,882**	**1,280,888**	**1,309,195**	**1,383,298**	**1,466,195**	**1,696,252**	**1,788,485**	**1,783,316**	**1,824,748**	**1,629,257**	**1,387,039**	**1,359,771**	**18,302,326**
4.	**Jurisdictional % of Total Sales**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	**1.0000000**	-
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	51,019,095	46,506,389	47,641,207	50,499,682	53,827,243	62,963,783	66,770,563	66,744,892	68,155,658	60,126,807	50,469,140	49,530,473	674,254,932
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,655	5,776,653	69,319,858
2a.	Incentive Provision	44,835	44,835	44,835	44,835	44,835	44,835	44,835	44,835	44,835	44,835	44,835	44,834	538,019
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**56,840,585**	**52,327,879**	**53,462,697**	**56,321,172**	**59,648,733**	**68,785,273**	**72,592,053**	**72,566,382**	**73,977,148**	**65,948,297**	**56,290,630**	**55,351,960**	**744,112,809**
4.	Total Fuel and Net Power Transactions (Line A6)	50,897,844	44,103,136	50,010,997	55,564,564	63,818,110	68,874,027	73,422,607	75,089,168	72,227,252	65,638,435	54,396,516	55,395,284	729,437,940
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	50,897,844	44,103,136	50,010,997	55,564,564	63,818,110	68,874,027	73,422,607	75,089,168	72,227,252	65,638,435	54,396,516	55,395,284	729,437,940
5a.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
5b.	Jurisdictional Sales Adjusted for Line Losses	50,897,844	44,103,136	50,010,997	55,564,564	63,818,110	68,874,027	73,422,607	75,089,168	72,227,252	65,638,435	54,396,516	55,395,284	729,437,940
5c.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS**	**50,897,844**	**44,103,136**	**50,010,997**	**55,564,564**	**63,818,110**	**68,874,027**	**73,422,607**	**75,089,168**	**72,227,252**	**65,638,435**	**54,396,516**	**55,395,284**	**729,437,940**
7.	Over/(Under) Recovery	5,942,741	8,224,743	3,451,700	756,608	(4,169,377)	(88,754)	(830,554)	(2,522,786)	1,749,896	309,862	1,894,114	(43,324)	14,674,869
7a.	Revenue Refund True-Up Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Interest Provision	4,218	5,729	5,735	4,761	3,632	2,632	4,640	5,843	4,920	4,208	3,508	2,781	52,607
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**14,727,476**

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		Actual						Estimated						TOTAL
		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	PERIOD
1.	Fuel Cost of System Net Generation	47,575,217	41,797,777	49,807,915	51,106,017	61,597,686	66,624,726	70,420,741	72,990,974	69,210,960	63,676,461	52,778,546	54,153,417	701,740,437
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	57,983	204,612	940,848	1,273,814	1,289,151	628,996	411,387	394,287	411,957	455,687	430,357	559,428	7,058,507
4.	Fuel Cost of Purchased Power	869,784	604,599	93,248	156,018	171,977	1,118,884	1,656,270	1,133,340	1,640,920	848,780	603,610	195,540	9,092,970
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	851,284	575,496	564,698	550,239	527,434	759,243	623,667	631,372	621,053	633,498	626,871	617,893	7,582,748
7.	Energy Cost of Economy Purchases	1,659,542	1,329,876	485,984	5,026,104	2,810,164	925,277	747,690	344,302	784,969	556,235	440,858	613,034	15,724,035
8.	Polk 1 Conversion Depreciation & ROI	0	0	0	0	0	74,893	385,626	383,467	381,307	379,148	376,988	374,828	2,356,257
8a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**50,897,844**	**44,103,136**	**50,010,997**	**55,564,564**	**63,818,110**	**68,874,027**	**73,422,607**	**75,089,168**	**72,227,252**	**65,638,435**	**54,396,516**	**55,395,284**	**729,437,940**
10.	Jurisdictional MWH Sold	1,393,882	1,280,888	1,309,195	1,383,298	1,466,195	1,696,252	1,788,485	1,783,316	1,824,748	1,629,257	1,387,039	1,359,771	18,302,326
11.	Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	50,897,844	44,103,136	50,010,997	55,564,564	63,818,110	68,874,027	73,422,607	75,089,168	72,227,252	65,638,435	54,396,516	55,395,284	729,437,940
13.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	50,897,844	44,103,136	50,010,997	55,564,564	63,818,110	68,874,027	73,422,607	75,089,168	72,227,252	65,638,435	54,396,516	55,395,284	729,437,940
15.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
16.	**JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 14+15)**	**50,897,844**	**44,103,136**	**50,010,997**	**55,564,564**	**63,818,110**	**68,874,027**	**73,422,607**	**75,089,168**	**72,227,252**	**65,638,435**	**54,396,516**	**55,395,284**	**729,437,940**
17.	Cost Per kWh Sold (Cents/kWh)	3.6515	3.4432	3.8200	4.0168	4.3526	4.0604	4.1053	4.2106	3.9582	4.0287	3.9218	4.0739	3.9855
18.	True-up (Cents/kWh) [2]	(0.4144)	(0.4510)	(0.4412)	(0.4176)	(0.3940)	(0.3406)	(0.3230)	(0.3239)	(0.3166)	(0.3546)	(0.4165)	(0.4248)	(0.3849)
19.	Total (Cents/kWh) (Line 17+18)	3.2371	2.9922	3.3788	3.5992	3.9586	3.7198	3.7823	3.8867	3.6416	3.6741	3.5053	3.6491	3.6007
20.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
21.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.2394	2.9944	3.3812	3.6018	3.9615	3.7225	3.7850	3.8895	3.6442	3.6767	3.5078	3.6517	3.6032
22.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0032)	(0.0035)	(0.0034)	(0.0032)	(0.0031)	(0.0026)	(0.0025)	(0.0025)	(0.0025)	(0.0028)	(0.0032)	(0.0033)	(0.0030)
23.	**TOTAL RECOVERY FACTOR (LINE 21+22)**	**3.2362**	**2.9909**	**3.3778**	**3.5986**	**3.9584**	**3.7199**	**3.7825**	**3.8870**	**3.6417**	**3.6739**	**3.5046**	**3.6484**	**3.6002**
24.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.236**	**2.991**	**3.378**	**3.599**	**3.958**	**3.720**	**3.783**	**3.887**	**3.642**	**3.674**	**3.505**	**3.648**	**3.600**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

SCHEDULE E3

	ACTUAL					
	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	569,602	563,813	742,615	203,514	(22,150)	4,644
3. COAL	24,464,225	16,236,277	30,045,365	24,651,021	31,926,565	32,924,310
4. NATURAL GAS	22,541,390	24,997,687	19,019,935	26,251,482	29,693,271	33,695,772
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**47,575,217**	**41,797,777**	**49,807,915**	**51,106,017**	**61,597,686**	**66,624,726**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	2,517	2,448	2,888	500	0	40
10. COAL	689,686	492,753	914,471	763,281	854,144	893,580
11. NATURAL GAS	577,318	727,221	496,133	645,500	728,230	863,933
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,269,521**	**1,222,422**	**1,413,492**	**1,409,281**	**1,582,374**	**1,757,553**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	4,547	4,479	5,852	1,594	(174)	35
17. COAL (TON)	298,817	220,243	391,806	335,418	374,633	404,256
18. NATURAL GAS (MCF)	4,287,064	5,283,555	3,706,166	4,801,870	5,399,416	6,417,498
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	20,292	17,949	23,990	6,083	(644)	15,718
23. COAL	7,389,231	5,389,328	9,409,201	7,923,061	8,967,013	9,494,252
24. NATURAL GAS	4,355,657	5,362,808	3,761,758	4,873,898	5,474,303	6,500,554
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**11,765,180**	**10,770,084**	**13,194,949**	**12,803,042**	**14,440,672**	**16,010,525**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.20	0.20	0.20	0.04	0.00	0.00
30. COAL	54.32	40.31	64.70	54.16	53.98	50.84
31. NATURAL GAS	45.48	59.49	35.10	45.80	46.02	49.16
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	125.27	125.88	126.90	127.68	127.30	132.69
37. COAL ($/TON)	81.87	73.72	76.68	73.49	85.22	81.44
38. NATURAL GAS ($/MCF)	5.26	4.73	5.13	5.47	5.50	5.25
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	28.07	31.41	30.96	33.46	34.39	0.00
43. COAL	3.31	3.01	3.19	3.11	3.56	3.47
44. NATURAL GAS	5.18	4.66	5.06	5.39	5.42	5.18
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.04**	**3.88**	**3.77**	**3.99**	**4.27**	**4.16**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	8,062	7,332	8,307	12,166	0	392,957
50. COAL	10,714	10,937	10,289	10,380	10,498	10,625
51. NATURAL GAS	7,545	7,374	7,582	7,551	7,517	7,524
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,267**	**8,810**	**9,335**	**9,085**	**9,126**	**9,110**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	22.63	23.03	25.71	40.70	0.00	11.61
57. COAL	3.55	3.30	3.29	3.23	3.74	3.68
58. NATURAL GAS	3.90	3.44	3.83	4.07	4.08	3.90
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.75**	**3.42**	**3.52**	**3.63**	**3.89**	**3.79**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2013 THROUGH DECEMBER 2013

SCHEDULE E3

	Estimated						
	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	293,494	237,898	302,812	239,672	240,455	286,055	3,662,424
3. COAL	39,540,572	40,620,815	39,083,254	34,767,262	36,273,596	33,297,009	383,830,271
4. NATURAL GAS	30,586,675	32,132,261	29,824,894	28,669,527	16,264,495	20,570,353	314,247,742
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**70,420,741**	**72,990,974**	**69,210,960**	**63,676,461**	**52,778,546**	**54,153,417**	**701,740,437**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	410	320	430	320	340	340	10,553
10. COAL	1,141,730	1,148,730	1,097,680	977,130	1,020,880	946,660	10,940,725
11. NATURAL GAS	720,940	744,870	650,910	634,230	308,870	452,170	7,550,325
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,863,080**	**1,893,920**	**1,749,020**	**1,611,680**	**1,330,090**	**1,399,170**	**18,501,603**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	5,850	5,410	5,880	6,300	7,190	5,730	52,693
17. COAL (TON)	487,390	490,150	468,830	417,420	437,760	403,240	4,729,963
18. NATURAL GAS (MCF)	5,521,860	5,660,450	5,000,630	4,719,200	2,433,100	3,243,310	56,474,119
19. NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	0	0	0	0	0	0	0
22. LIGHT OIL	15,760	12,620	15,950	12,620	12,700	14,570	167,608
23. COAL	11,655,800	11,720,380	11,213,180	9,983,470	10,485,180	9,684,360	113,314,456
24. NATURAL GAS	5,671,960	5,814,440	5,136,140	4,842,340	2,496,730	3,329,610	57,620,198
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**17,343,520**	**17,547,440**	**16,365,270**	**14,838,430**	**12,994,610**	**13,028,540**	**171,102,262**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.03	0.02	0.06
30. COAL	61.28	60.65	62.76	60.63	76.75	67.66	59.13
31. NATURAL GAS	38.70	39.33	37.22	39.35	23.22	32.32	40.81
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	50.17	43.97	51.50	38.04	33.44	49.92	69.50
37. COAL ($/TON)	81.13	82.87	83.36	83.29	82.86	82.57	81.15
38. NATURAL GAS ($/MCF)	5.54	5.68	5.96	6.08	6.68	6.34	5.56
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	18.62	18.85	18.99	18.99	18.93	19.63	21.85
43. COAL	3.39	3.47	3.49	3.48	3.46	3.44	3.39
44. NATURAL GAS	5.39	5.53	5.81	5.92	6.51	6.18	5.45
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.06**	**4.16**	**4.23**	**4.29**	**4.06**	**4.16**	**4.10**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	38,439	39,438	37,093	39,438	37,353	42,853	15,883
50. COAL	10,209	10,203	10,215	10,217	10,271	10,230	10,357
51. NATURAL GAS	7,867	7,806	7,891	7,635	8,083	7,364	7,631
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,309**	**9,265**	**9,357**	**9,207**	**9,770**	**9,312**	**9,248**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	71.58	74.34	70.42	74.90	70.72	84.13	34.71
57. COAL	3.46	3.54	3.56	3.56	3.55	3.52	3.51
58. NATURAL GAS	4.24	4.31	4.58	4.52	5.27	4.55	4.16
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.78**	**3.85**	**3.96**	**3.95**	**3.97**	**3.87**	**3.79**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2013

SCHEDULE A4
PAGE 1 OF 1
REVISED 7/19/13

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	395	45,745	15.6	16.4	94.6	10,648	COAL	20,314	23,978,000	487,097.5	1,589,631	3.47	78.25
B.B.#2	395	101,821	34.6	36.5	92.6	9,937	COAL	42,761	23,662,000	1,011,811.0	3,346,176	3.29	78.25
B.B.#3	365	220,461	81.2	84.0	81.2	10,806	COAL	98,754	24,124,000	2,382,342.7	7,727,796	3.51	78.25
B.B.#4	417	172,056	55.5	56.7	55.5	11,062	COAL	79,220	24,026,000	1,903,346.4	6,199,202	3.60	78.25
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	1,619	5,729,445	9,277.9	211,064	-	130.37
B.B. COAL	**1,572**	**540,083**	**46.2**	**47.8**	**73.0**	**10,711**	-	-	-	-	**19,073,869**	**3.53**	-
B.B.C.T.#4 (GAS)	61	547	1.2	92.5	69.1	14,016	GAS	7,546	1,016,000	7,667.0	37,683	6.89	4.99
B.B.C.T.#4 (OIL)	61	0	0.0	92.5	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T. #4 TOTAL	**61**	**547**	**1.2**	**92.4**	**69.1**	**14,016**	-	-	-	**7,667.0**	**37,683**	**6.89**	-
BIG BEND STATION TOTAL	**1,633**	**540,630**	**44.5**	**49.5**	**73.0**	**10,714**	-	-	-	**5,792,264.6**	**19,111,552**	**3.54**	-
POLK #1 GASIFIER	220	149,603	91.4	88.9	100.5	10,726	COAL	57,768	27,777,430	1,604,633.2	5,390,356	3.60	93.31
POLK #1 CT (OIL)	235	2,517	1.4	93.9	49.4	9,200	LGT.OIL	4,547	5,800,000	20,292.3	569,602	22.63	125.27
POLK #1 TOTAL	**220**	**152,120**	**92.9**	**93.9**	**99.0**	**10,701**	-	-	-	**1,624,925.5**	**5,959,958**	**3.92**	-
POLK #2 CT (GAS)	183	6,023	4.4	100.0	64.5	11,970	GAS	70,961	1,016,000	72,096.0	406,869	6.76	5.73
POLK #2 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**183**	**6,023**	**4.4**	**99.9**	**64.5**	**11,970**	-	-	-	**72,096.0**	**406,869**	**6.76**	-
POLK #3 CT (GAS)	183	3,510	2.6	100.0	67.5	12,087	GAS	41,757	1,016,000	42,425.0	240,094	6.84	5.75
POLK #3 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**183**	**3,510**	**2.6**	**100.0**	**67.5**	**12,087**	-	-	-	**42,425.0**	**240,094**	**6.84**	-
POLK #4 (GAS) [3]	**183**	**(188)**	**0.0**	**100.0**	**0.0**	**0**	GAS	**0**	**0**	**0.0**	**(666)**	**0.35**	**0.00**
POLK #5 (GAS)	**183**	**8,640**	**6.3**	**100.0**	**64.8**	**11,489**	GAS	**97,698**	**1,016,000**	**99,261.0**	**561,440**	**6.50**	**5.75**
POLK STATION TOTAL	**952**	**170,105**	**24.0**	**98.6**	**93.7**	**10,826**	-	-	-	**1,838,707.5**	**7,167,695**	**4.21**	-
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
COT 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
CITY OF TAMPA TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**294**	**0.00**	**0.00**
BAYSIDE ST 1	243	98,297	54.4	100.0	71.7	-	-	-	-	-	-	-	-
BAYSIDE CT1A	183	61,579	45.2	99.7	74.5	11,400	GAS	691,033	1,016,000	702,090.0	3,598,112	5.84	5.21
BAYSIDE CT1B	183	56,641	41.6	99.9	75.5	11,232	GAS	626,383	1,016,000	636,405.0	3,261,489	5.76	5.21
BAYSIDE CT1C	183	66,784	49.1	100.0	71.4	10,942	GAS	719,479	1,016,000	730,991.0	3,746,227	5.61	5.21
BAYSIDE UNIT 1 TOTAL	**792**	**283,301**	**48.1**	**99.9**	**63.4**	**7,303**	**GAS**	**2,036,895**	**1,016,000**	**2,069,486.0**	**10,605,828**	**3.74**	**5.21**
BAYSIDE ST 2	315	92,829	39.6	100.0	60.8	-	-	-	-	-	-	-	-
BAYSIDE CT2A	183	52,252	38.4	100.0	76.1	11,121	GAS	572,155	1,016,000	581,309.0	3,015,019	5.77	5.27
BAYSIDE CT2B	183	60,253	44.3	89.5	75.3	11,340	GAS	672,653	1,016,000	683,416.0	3,544,602	5.88	5.27
BAYSIDE CT2C	183	0	0.0	0.0	0.0	0	GAS	0	1,016,000	0.0	0	0.00	0.00
BAYSIDE CT2D	183	63,233	46.4	100.0	69.2	11,452	GAS	712,880	1,016,000	724,286.0	3,756,582	5.94	5.27
BAYSIDE UNIT 2 TOTAL	**1,047**	**268,567**	**34.5**	**72.4**	**52.9**	**7,404**	**GAS**	**1,957,688**	**1,016,000**	**1,989,011.0**	**10,316,203**	**3.84**	**5.27**
BAYSIDE UNIT 3 TOTAL	**61**	**641**	**1.4**	**100.0**	**87.8**	**11,733**	**GAS**	**7,403**	**1,016,000**	**7,521.0**	**33,169**	**5.17**	**4.48**
BAYSIDE UNIT 4 TOTAL	**61**	**3,312**	**7.3**	**89.3**	**108.0**	**10,800**	**GAS**	**35,210**	**1,016,000**	**35,773.0**	**174,832**	**5.28**	**4.97**
BAYSIDE UNIT 5 TOTAL	**61**	**1,858**	**4.1**	**100.0**	**92.9**	**10,902**	**GAS**	**19,936**	**1,016,000**	**20,255.0**	**103,809**	**5.59**	**5.21**
BAYSIDE UNIT 6 TOTAL	**61**	**1,107**	**2.4**	**100.0**	**89.7**	**10,985**	**GAS**	**11,970**	**1,016,000**	**12,162.0**	**61,835**	**5.59**	**5.17**
BAYSIDE STATION TOTAL	**2,083**	**558,786**	**36.1**	**85.8**	**58.1**	**7,397**	**GAS**	**4,069,102**	**1,016,000**	**4,134,208.0**	**21,295,676**	**3.81**	**5.23**
SYSTEM	**4,668**	**1,269,521**	**36.6**	**75.7**	**67.4**	**9,269**	-	-	-	**11,765,180.1**	**47,575,217**	**3.75**	-

Footnotes:
[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] Station Service

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 6 of 25

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2013

SCHEDULE A4
PAGE 1 OF 1
REVISED 7/19/13

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	395	32,994	12.4	14.3	52.5	11,337	COAL	15,507	24,122,000	374,053.3	1,114,792	3.38	71.89
B.B.#2	395	119,862	45.2	50.3	70.0	11,138	COAL	55,603	24,010,000	1,335,039.1	3,997,278	3.33	71.89
B.B.#3	365	188,638	76.9	79.0	76.9	10,813	COAL	85,621	23,822,000	2,039,659.7	6,155,261	3.26	71.89
B.B.#4	417	60,827	21.7	22.4	55.7	10,830	COAL	27,818	23,680,000	658,730.0	1,999,826	3.29	71.89
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	5,214	5,730,885	29,882.3	681,321	-	130.67
B.B. COAL	**1,572**	**402,321**	**38.1**	**40.5**	**68.4**	**10,955**	-	-	-	-	**13,948,478**	**3.47**	-
B.B.C.T.#4 (GAS)	61	474	1.2	93.2	70.3	13,725	GAS	6,409	1,015,000	6,505.5	30,307	6.39	4.73
B.B.C.T.#4 (OIL)	61	0	0.0	93.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T. #4 TOTAL	**61**	**474**	**1.2**	**93.2**	**70.3**	**13,725**	-	-	-	**6,505.5**	**30,307**	**6.39**	-
BIG BEND STATION TOTAL	**1,633**	**402,795**	**36.7**	**42.5**	**68.4**	**10,958**	-	-	-	**4,413,987.6**	**13,978,785**	**3.47**	-
POLK #1 GASIFIER	220	90,432	61.2	80.5	97.7	10,857	COAL	35,694	27,507,304	981,845.4	2,287,799	2.53	64.09
POLK #1 CT (OIL)	235	2,448	1.6	85.7	45.3	9,030	LGT.OIL	4,479	5,800,000	17,949.4	563,813	23.03	125.88
POLK #1 TOTAL	**220**	**92,880**	**62.8**	**85.7**	**95.2**	**10,809**	-	-	-	**999,794.8**	**2,851,612**	**3.07**	-
POLK #2 CT (GAS)	183	2,608	2.1	95.0	26.5	12,271	GAS	31,530	1,015,000	32,003.0	173,707	6.66	5.51
POLK #2 CT (OIL)	187	0	0.0	95.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**183**	**2,608**	**2.1**	**95.0**	**26.5**	**12,271**	-	-	-	**32,003.0**	**173,707**	**6.66**	-
POLK #3 CT (GAS)	183	1,509	1.2	96.2	63.2	13,668	GAS	20,320	1,015,000	20,625.0	111,948	7.42	5.51
POLK #3 CT (OIL)	187	0	0.0	96.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**183**	**1,509**	**1.2**	**96.2**	**63.2**	**13,668**	-	-	-	**20,625.0**	**111,948**	**7.42**	-
POLK #4 (GAS) [3]	**183**	**(33)**	**0.0**	**93.8**	**0.0**	**0**	GAS	**1,421**	**1,015,000**	**1,442.0**	**7,826**	**(23.72)**	**5.51**
POLK #5 (GAS)	**183**	**4,471**	**3.6**	**95.3**	**69.0**	**10,646**	GAS	**46,895**	**1,015,000**	**47,598.0**	**258,353**	**5.78**	**5.51**
POLK STATION TOTAL	**952**	**101,435**	**15.9**	**92.9**	**87.1**	**10,900**	-	-	-	**1,101,462.8**	**3,403,446**	**3.36**	-
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
COT 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
CITY OF TAMPA TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**294**	**0.00**	**0.00**
BAYSIDE ST 1	243	123,935	75.9	100.0	75.9	-		-	-	-	-	-	-
BAYSIDE CT1A	183	66,450	54.0	100.0	78.7	11,134	GAS	728,827	1,015,000	739,759.0	3,437,239	5.17	4.72
BAYSIDE CT1B	183	92,064	74.9	100.0	78.7	11,011	GAS	998,552	1,015,000	1,013,530.0	4,709,295	5.12	4.72
BAYSIDE CT1C	183	79,192	64.4	100.0	78.3	10,732	GAS	837,157	1,015,000	849,714.0	3,948,136	4.99	4.72
BAYSIDE UNIT 1 TOTAL	**792**	**361,641**	**67.9**	**100.0**	**67.9**	**7,199**	**GAS**	**2,564,536**	**1,015,000**	**2,603,003.0**	**12,094,670**	**3.34**	**4.72**
BAYSIDE ST 2	315	120,091	56.7	100.0	56.7	-		-	-	-	-	-	-
BAYSIDE CT2A	183	61,843	50.3	100.0	78.2	11,087	GAS	675,321	1,015,000	685,451.0	3,184,879	5.15	4.72
BAYSIDE CT2B	183	94,557	76.9	99.9	77.8	11,273	GAS	1,050,055	1,015,000	1,065,806.0	4,952,161	5.24	4.72
BAYSIDE CT2C	183	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE CT2D	183	74,861	60.9	100.0	75.8	11,257	GAS	830,121	1,015,000	842,573.0	3,914,931	5.23	4.72
BAYSIDE UNIT 2 TOTAL	**1,047**	**351,352**	**49.9**	**75.0**	**49.9**	**7,384**	**GAS**	**2,555,497**	**1,015,000**	**2,593,830.0**	**12,051,971**	**3.43**	**4.72**
BAYSIDE UNIT 3 TOTAL	**61**	**961**	**2.3**	**87.4**	**91.2**	**11,216**	**GAS**	**10,620**	**1,015,000**	**10,779.0**	**50,084**	**5.21**	**4.72**
BAYSIDE UNIT 4 TOTAL	**61**	**2,905**	**7.1**	**100.0**	**94.3**	**10,930**	**GAS**	**31,278**	**1,015,000**	**31,747.0**	**147,525**	**5.08**	**4.72**
BAYSIDE UNIT 5 TOTAL	**61**	**667**	**1.6**	**99.7**	**40.9**	**11,640**	**GAS**	**7,649**	**1,015,000**	**7,764.0**	**36,095**	**5.41**	**4.72**
BAYSIDE UNIT 6 TOTAL	**61**	**666**	**1.6**	**62.2**	**89.6**	**11,281**	**GAS**	**7,400**	**1,015,000**	**7,511.0**	**34,907**	**5.24**	**4.72**
BAYSIDE STATION TOTAL [4]	**2,083**	**718,192**	**51.3**	**85.9**	**57.8**	**7,318**	**GAS**	**5,176,980**	**1,015,000**	**5,254,634.0**	**24,415,252**	**3.40**	**4.72**
SYSTEM	**4,668**	**1,222,422**	**39.0**	**72.2**	**62.8**	**8,815**	-	-	-	**10,770,084.4**	**41,797,777**	**3.42**	-

Footnotes:
[1] As burned fuel cost system total includes ignition oil
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] Station Service
[4] Includes adjustment to Bayside consumption of (1,080) bbls and fuel cost of ($91) and mmbtu's of (1,098) for January 2013.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 7 of 25

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2013

SCHEDULE A4
PAGE 1 OF 1
REVISED 7/19/13

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	395	218,329	74.4	78.8	83.3	10,523	COAL	96,132	23,898,000	2,297,373.1	7,339,321	3.36	76.35
B.B.#2	395	271,581	92.5	96.8	92.5	10,173	COAL	117,562	23,500,000	2,762,711.0	8,975,422	3.30	76.35
B.B.#3	365	4,505	1.7	2.1	58.5	11,207	COAL	2,206	22,886,000	50,486.5	168,420	3.74	76.35
B.B.#4	417	269,732	87.1	92.4	89.6	10,167	COAL	119,239	23,000,000	2,742,469.6	9,103,455	3.38	76.35
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	2,559	5,732,755	14,669.4	335,801	-	131.22
B.B. COAL	**1,572**	**764,147**	**65.4**	**69.1**	**88.4**	**10,277**	-	-	-	-	**25,922,419**	**3.39**	-
B.B.C.T.#4 (GAS)	61	8	0.0	96.2	7.3	145,125	GAS	1,144	1,015,000	1,161.0	6,167	77.09	5.39
B.B.C.T.#4 (OIL)	61	0	0.0	96.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T. #4 TOTAL	**61**	**8**	**0.0**	**96.2**	**7.3**	**145,125**	-	-	-	**1,161.0**	**6,167**	**77.09**	-
BIG BEND STATION TOTAL	**1,633**	**764,155**	**63.0**	**70.1**	**88.4**	**10,278**	-	-	-	**7,854,201.2**	**25,928,586**	**3.39**	-
POLK #1 GASIFIER	220	150,324	92.0	98.2	99.0	10,352	COAL	56,667	27,461,437	1,556,161.1	4,122,946	2.74	72.76
POLK #1 CT (OIL) [4]	235	2,888	1.7	98.7	44.4	10,983	LGT.OIL	5,852	5,800,000	23,989.9	742,615	25.71	126.90
POLK #1 TOTAL	**220**	**153,212**	**93.7**	**98.7**	**97.0**	**10,364**	-	-	-	**1,580,151.0**	**4,865,561**	**3.18**	-
POLK #2 CT (GAS) [3]	183	(258)	0.0	100.0	0.0	0	GAS	0	0	0.0	1	(0.00)	0.00
POLK #2 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**183**	**(258)**	**0.0**	**100.0**	**0.0**	**0**	-	-	-	**0.0**	**1**	**(0.00)**	-
POLK #3 CT (GAS)	183	1,416	1.0	100.0	65.6	12,664	GAS	17,667	1,015,000	17,932.0	97,425	6.88	5.51
POLK #3 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**183**	**1,416**	**1.0**	**100.0**	**65.6**	**12,664**	-	-	-	**17,932.0**	**97,425**	**6.88**	-
POLK #4 (GAS)	**183**	**118**	**0.1**	**98.0**	**24.5**	**25,186**	GAS	**2,928**	**1,015,000**	**2,972.0**	**16,147**	**13.68**	**5.51**
POLK #5 (GAS)	**183**	**2,172**	**1.6**	**100.0**	**52.8**	**12,564**	GAS	**26,887**	**1,015,000**	**27,290.0**	**148,267**	**6.83**	**5.51**
POLK STATION TOTAL	**952**	**156,660**	**22.1**	**99.3**	**95.1**	**10,443**	-	-	-	**1,628,345.0**	**5,127,401**	**3.27**	-
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
COT 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
CITY OF TAMPA TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**294**	**0.00**	**0.00**
BAYSIDE ST 1	243	65,526	36.3	76.9	47.2	-		-	-	-	-	-	-
BAYSIDE CT1A	183	35,188	25.9	69.9	75.5	11,330	GAS	392,777	1,015,000	398,669.0	2,013,728	5.72	5.13
BAYSIDE CT1B	183	49,439	36.4	74.4	71.5	11,405	GAS	555,483	1,015,000	563,815.0	2,847,905	5.76	5.13
BAYSIDE CT1C	183	39,923	29.4	75.1	70.6	11,264	GAS	443,035	1,015,000	449,680.0	2,271,395	5.69	5.13
BAYSIDE UNIT 1 TOTAL [4]	**792**	**190,076**	**32.3**	**72.7**	**42.0**	**7,430**	**GAS**	**1,391,295**	**1,015,000**	**1,412,164.0**	**7,133,028**	**3.75**	**5.13**
BAYSIDE ST 2	315	102,381	43.7	99.8	43.8	-		-	-	-	-	-	-
BAYSIDE CT2A	183	41,595	30.6	90.8	75.9	11,257	GAS	461,295	1,015,000	468,214.0	2,364,970	5.69	5.13
BAYSIDE CT2B	183	93,257	68.6	99.8	73.1	11,588	GAS	1,064,707	1,015,000	1,080,677.0	5,458,546	5.85	5.13
BAYSIDE CT2C	183	0	0.0	0.0	0.0	0	GAS	0	1,015,000	0.0	0	0.00	0.00
BAYSIDE CT2D	183	61,552	45.3	96.0	74.0	11,510	GAS	697,980	1,015,000	708,450.0	3,578,409	5.81	5.13
BAYSIDE UNIT 2 TOTAL [4]	**1,047**	**298,785**	**38.4**	**71.6**	**38.5**	**7,555**	**GAS**	**2,223,982**	**1,015,000**	**2,257,341.0**	**11,401,925**	**3.82**	**5.13**
BAYSIDE UNIT 3 TOTAL	**61**	**24**	**0.1**	**100.0**	**35.2**	**27,167**	**GAS**	**642**	**1,015,000**	**652.0**	**3,294**	**13.73**	**5.13**
BAYSIDE UNIT 4 TOTAL	**61**	**2,665**	**5.9**	**100.0**	**61.9**	**10,984**	**GAS**	**28,840**	**1,015,000**	**29,273.0**	**147,859**	**5.55**	**5.13**
BAYSIDE UNIT 5 TOTAL	**61**	**1,073**	**2.4**	**99.3**	**90.8**	**11,363**	**GAS**	**12,013**	**1,015,000**	**12,193.0**	**61,587**	**5.74**	**5.13**
BAYSIDE UNIT 6 TOTAL	**61**	**54**	**0.1**	**100.0**	**65.6**	**14,444**	**GAS**	**768**	**1,015,000**	**780.0**	**3,941**	**7.30**	**5.13**
BAYSIDE STATION TOTAL	**2,083**	**492,677**	**31.8**	**75.3**	**39.9**	**7,535**	**GAS**	**3,657,540**	**1,015,000**	**3,712,403.0**	**18,751,634**	**3.81**	**5.13**
SYSTEM	**4,668**	**1,413,492**	**40.8**	**78.4**	**62.4**	**9,341**	-	-	-	**13,194,949.2**	**49,807,915**	**3.52**	-

Footnotes:
[1] As burned fuel cost system total includes ignition oil
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] Station Service
[4] Includes consumption & fuel cost adjustments to Bayside 1 & 2 of (129) mcf and ($9) and to Polk #1 CT of 138 bbls and $17,397 for February 2013.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 8 of 25

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2013

SCHEDULE A4
PAGE 1 OF 1
REVISED 7/19/13

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	385	237,862	85.8	87.3	94.8	10,378	COAL	103,094	23,944,000	2,468,477.7	7,753,722	3.26	75.21
B.B.#2	385	202,976	73.2	76.3	91.3	10,118	COAL	87,927	23,356,000	2,053,634.5	6,613,008	3.26	75.21
B.B.#3	365	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B.#4	407	288,798	98.6	99.5	98.6	10,376	COAL	129,717	23,100,000	2,996,459.2	9,756,043	3.38	75.21
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	1,861	5,733,357	10,667.3	244,229	-	131.24
B.B. COAL	**1,542**	**729,636**	**65.7**	**67.1**	**95.2**	**10,305**	-	-	-	-	**24,367,002**	**3.34**	-
B.B.C.T.#4 (GAS)	56	1,085	2.7	59.2	87.1	13,854	GAS	14,811	1,015,000	15,033.0	80,468	7.42	5.43
B.B.C.T.#4 (OIL)	56	72	0.2	59.2	87.2	6,998	LGT.OIL	88	5,733,355	503.1	11,519	16.00	130.90
B.B.C.T. #4 TOTAL	**56**	**1,157**	**2.9**	**59.2**	**87.1**	**13,428**	-	-	-	**15,536.1**	**91,987**	**7.95**	-
BIG BEND STATION TOTAL	**1,598**	**730,793**	**63.5**	**66.8**	**95.2**	**10,309**	-	-	-	**7,534,107.5**	**24,458,989**	**3.35**	-
POLK #1 GASIFIER	220	33,645	21.2	41.1	84.3	12,022	COAL	14,680	27,553,457	404,489.4	284,019	0.84	19.35
POLK #1 CT (OIL)	218	428	0.3	43.3	56.7	13,289	LGT.OIL	1,506	5,753,800	5,579.8	191,995	44.86	127.49
POLK #1 TOTAL	**220**	**34,073**	**21.5**	**43.3**	**83.7**	**12,038**	-	-	-	**410,069.2**	**476,014**	**1.40**	-
POLK #2 CT (GAS)	151	5,372	4.9	83.9	78.3	12,353	GAS	65,380	1,015,000	66,361.0	324,124	6.03	4.96
POLK #2 CT (OIL)	159	0	0.0	83.9	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**151**	**5,372**	**4.9**	**83.9**	**78.3**	**12,353**	-	-	-	**66,361.0**	**324,124**	**6.03**	-
POLK #3 CT (GAS)	151	2,680	2.5	84.1	9.9	11,298	GAS	29,831	1,015,000	30,278.0	147,648	5.51	4.95
POLK #3 CT (OIL)	159	0	0.0	84.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**151**	**2,680**	**2.5**	**84.1**	**9.9**	**11,298**	-	-	-	**30,278.0**	**147,648**	**5.51**	-
POLK #4 (GAS)	**151**	**3,308**	**3.0**	**98.6**	**73.9**	**12,408**	GAS	**40,439**	**1,015,000**	**41,046.0**	**201,214**	**6.08**	**4.98**
POLK #5 (GAS)	**151**	**5,465**	**5.0**	**98.6**	**78.1**	**11,891**	GAS	**64,024**	**1,015,000**	**64,984.0**	**316,755**	**5.80**	**4.95**
POLK STATION TOTAL	**824**	**50,898**	**8.6**	**78.5**	**59.2**	**12,041**	-	-	-	**612,738.2**	**1,465,755**	**2.88**	-
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
COT 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
CITY OF TAMPA TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**294**	**0.00**	**0.00**
BAYSIDE ST 1	233	115,961	69.1	100.0	69.1	-	-	-	-	-	-	-	-
BAYSIDE CT1A	156	63,797	56.8	100.0	86.9	11,418	GAS	717,690	1,015,000	728,455.0	3,941,081	6.18	5.49
BAYSIDE CT1B	156	68,010	60.5	99.9	86.5	11,328	GAS	759,021	1,015,000	770,407.0	4,168,043	6.13	5.49
BAYSIDE CT1C	156	83,603	74.4	100.0	86.2	11,049	GAS	910,088	1,015,000	923,739.0	4,997,605	5.98	5.49
BAYSIDE UNIT 1 TOTAL	**701**	**331,371**	**65.7**	**100.0**	**65.7**	**7,311**	**GAS**	**2,386,799**	**1,015,000**	**2,422,601.0**	**13,106,729**	**3.96**	**5.49**
BAYSIDE ST 2	305	99,808	45.4	74.7	60.9	-	-	-	-	-	-	-	-
BAYSIDE CT2A	156	32,259	28.7	53.1	88.5	11,207	GAS	356,188	1,015,000	361,531.0	1,954,279	6.06	5.49
BAYSIDE CT2B	156	52,375	46.6	76.4	88.6	11,404	GAS	588,449	1,015,000	597,276.0	3,228,615	6.16	5.49
BAYSIDE CT2C	156	61,292	54.6	76.4	88.9	11,355	GAS	685,665	1,015,000	695,950.0	3,762,005	6.14	5.49
BAYSIDE CT2D	156	45,313	40.3	86.2	87.1	11,478	GAS	512,398	1,015,000	520,084.0	2,811,350	6.20	5.49
BAYSIDE UNIT 2 TOTAL	**929**	**291,047**	**43.5**	**62.9**	**58.3**	**7,472**	**GAS**	**2,142,700**	**1,015,000**	**2,174,841.0**	**11,756,249**	**4.04**	**5.49**
BAYSIDE UNIT 3 TOTAL	**56**	**672**	**1.7**	**83.3**	**32.7**	**11,563**	**GAS**	**7,655**	**1,015,000**	**7,770.0**	**41,943**	**6.24**	**5.48**
BAYSIDE UNIT 4 TOTAL	**56**	**2,037**	**5.1**	**86.8**	**95.1**	**11,161**	**GAS**	**22,398**	**1,015,000**	**22,734.0**	**122,675**	**6.02**	**5.48**
BAYSIDE UNIT 5 TOTAL	**56**	**1,157**	**2.9**	**81.2**	**94.3**	**11,595**	**GAS**	**13,217**	**1,015,000**	**13,415.0**	**72,804**	**6.29**	**5.51**
BAYSIDE UNIT 6 TOTAL	**56**	**1,306**	**3.2**	**75.2**	**92.5**	**11,359**	**GAS**	**14,616**	**1,015,000**	**14,835.0**	**80,579**	**6.17**	**5.51**
BAYSIDE STATION TOTAL	**1,854**	**627,590**	**47.0**	**79.2**	**62.1**	**7,419**	**GAS**	**4,587,385**	**1,015,000**	**4,656,196.0**	**25,180,979**	**4.01**	**5.49**
SYSTEM	**4,276**	**1,409,281**	**45.8**	**74.4**	**75.6**	**9,085**	-	-	-	**12,803,041.7**	**51,106,017**	**3.63**	-

Footnotes:
[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 9 of 25

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2013

SCHEDULE A4
PAGE 1 OF 1
REVISED 7/19/13

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	385	240,612	84.0	88.0	94.8	10,581	COAL	105,187	24,204,000	2,545,937.0	8,440,632	3.51	80.24
B.B.#2	385	278,394	97.2	98.6	97.2	10,284	COAL	118,409	24,178,000	2,862,904.4	9,501,619	3.41	80.24
B.B.#3	365	86,122	31.7	32.8	92.7	10,189	COAL	37,488	23,408,000	877,509.3	3,008,189	3.49	80.24
B.B.#4	407	253,441	83.7	85.0	92.7	10,577	COAL	113,549	23,608,000	2,680,662.0	9,111,632	3.60	80.24
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	4,997	5,737,193	14,440,672.3	655,414	-	131.16
B.B. COAL	**1,542**	**858,569**	**74.8**	**76.8**	**94.7**	**10,444**	-	-	-	-	**30,717,486**	**3.58**	-
B.B.C.T.#4 (GAS)	56	320	0.8	100.0	73.9	17,163	GAS	5,411	1,015,000	5,492.3	29,836	9.32	5.51
B.B.C.T.#4 (OIL)	56	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T. #4 TOTAL	**56**	**320**	**0.8**	**100.0**	**73.9**	**17,163**	-	-	-	**5,492.3**	**29,836**	**9.32**	-
BIG BEND STATION TOTAL	**1,598**	**858,889**	**72.2**	**77.6**	**94.7**	**10,447**	-	-	-	**8,972,505.0**	**30,747,322**	**3.58**	-
POLK #1 GASIFIER	220	(4,425)	0.0	0.0	0.0	0	COAL	0	0	0.0	1,209,079	(27.32)	0.00
POLK #1 CT (GAS)	218	(184)	0.0	0.0	0.0	0	GAS	6,014	0	0.0	33,843	(18.39)	5.63
POLK #1 CT (OIL) [3]	-	-	-	-	-	-	LGT.OIL	(174)	-	(643.7)	(22,150)	-	127.30
POLK #1 TOTAL	**220**	**(4,609)**	**0.0**	**0.0**	**0.0**	**0**	-	-	-	**(643.7)**	**1,220,772**	**(26.49)**	-
POLK #2 CT (GAS)	151	3,286	2.9	53.8	81.8	12,238	GAS	39,619	1,015,000	40,213.0	220,627	6.71	5.57
POLK #2 CT (OIL)	159	0	0.0	53.8	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**151**	**3,286**	**2.9**	**53.8**	**81.8**	**12,238**	-	-	-	**40,213.0**	**220,627**	**6.71**	-
POLK #3 CT (GAS)	151	3,233	2.9	59.9	81.6	12,015	GAS	38,270	1,015,000	38,844.0	214,212	6.63	5.60
POLK #3 CT (OIL)	159	0	0.0	59.9	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**151**	**3,233**	**2.9**	**59.9**	**81.6**	**12,015**	-	-	-	**38,844.0**	**214,212**	**6.63**	-
POLK #4 (GAS)	**151**	**1,671**	**1.5**	**100.0**	**70.1**	**12,941**	GAS	**21,304**	**1,015,000**	**21,624.0**	**118,346**	**7.08**	**5.56**
POLK #5 (GAS)	**151**	**5,095**	**4.5**	**98.9**	**74.1**	**11,960**	GAS	**60,035**	**1,015,000**	**60,936.0**	**335,459**	**6.58**	**5.59**
POLK STATION TOTAL	**824**	**8,676**	**1.4**	**57.3**	**50.3**	**18,628**	-	-	-	**160,973.3**	**2,109,416**	**24.31**	-
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
COT 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	147	0.00	0.00
CITY OF TAMPA TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**294**	**0.00**	**0.00**
BAYSIDE ST 1	233	108,361	62.5	100.0	62.5	-	-	-	-	-	-	-	-
BAYSIDE CT1A	156	71,739	61.8	100.0	87.1	11,351	GAS	802,283	1,015,000	814,317.0	4,404,894	6.14	5.49
BAYSIDE CT1B	156	67,920	58.5	99.4	87.6	11,223	GAS	751,023	1,015,000	762,288.0	4,123,454	6.07	5.49
BAYSIDE CT1C	156	64,450	55.5	99.4	83.2	10,955	GAS	695,592	1,015,000	706,026.0	3,819,113	5.93	5.49
BAYSIDE UNIT 1 TOTAL	**701**	**312,470**	**59.9**	**99.6**	**59.9**	**7,305**	**GAS**	**2,248,898**	**1,015,000**	**2,282,631.0**	**12,347,461**	**3.95**	**5.49**
BAYSIDE ST 2	305	135,364	59.7	98.8	60.4	-	-	-	-	-	-	-	-
BAYSIDE CT2A	156	57,919	49.9	97.0	90.3	11,110	GAS	633,997	1,015,000	643,506.0	3,487,849	6.02	5.50
BAYSIDE CT2B	156	54,295	46.8	100.0	90.1	11,315	GAS	605,248	1,015,000	614,327.0	3,329,690	6.13	5.50
BAYSIDE CT2C	156	95,588	82.4	100.0	86.5	11,447	GAS	1,078,011	1,015,000	1,094,181.0	5,930,533	6.20	5.50
BAYSIDE CT2D	156	52,948	45.6	100.0	89.0	11,372	GAS	593,204	1,015,000	602,102.0	3,263,432	6.16	5.50
BAYSIDE UNIT 2 TOTAL	**929**	**396,114**	**57.3**	**98.0**	**58.0**	**7,458**	**GAS**	**2,910,460**	**1,015,000**	**2,954,116.0**	**16,011,504**	**4.04**	**5.50**
BAYSIDE UNIT 3 TOTAL	**56**	**770**	**1.8**	**100.0**	**93.0**	**11,587**	**GAS**	**8,790**	**1,015,000**	**8,922.0**	**48,352**	**6.28**	**5.50**
BAYSIDE UNIT 4 TOTAL	**56**	**2,104**	**5.0**	**100.0**	**97.4**	**11,181**	**GAS**	**23,176**	**1,015,000**	**23,524.0**	**127,272**	**6.05**	**5.49**
BAYSIDE UNIT 5 TOTAL	**56**	**2,249**	**5.4**	**100.0**	**99.8**	**11,399**	**GAS**	**25,258**	**1,015,000**	**25,637.0**	**139,206**	**6.19**	**5.51**
BAYSIDE UNIT 6 TOTAL	**56**	**1,102**	**2.6**	**100.0**	**99.6**	**11,220**	**GAS**	**12,181**	**1,015,000**	**12,364.0**	**66,859**	**6.07**	**5.49**
BAYSIDE STATION TOTAL	**1,854**	**714,809**	**51.8**	**98.9**	**59.0**	**7,425**	**GAS**	**5,228,763**	**1,015,000**	**5,307,194.0**	**28,740,654**	**4.02**	**5.50**
SYSTEM	**4,276**	**1,582,374**	**49.7**	**82.9**	**74.1**	**9,126**	-	-	-	**14,440,672.3**	**61,597,686**	**3.89**	-

Footnotes:
[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] Polk CT1 oil converted to natural gas, negative amounts shown are due to prior period adjustments. Includes April adjustment of (174) bbls and ($22,150).

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2013

SCHEDULE A4
PAGE 1 OF 1

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
B.B.#1	385	212,558	76.7	80.1	91.8	10,560	COAL	95,303	23,552,000	2,244,579.8	7,501,466	3.53	78.71
B.B.#2	385	259,235	93.5	96.5	93.5	10,263	COAL	112,819	23,582,000	2,660,490.1	8,880,181	3.43	78.71
B.B.#3	365	232,486	88.5	87.8	98.8	10,231	COAL	104,297	22,806,000	2,378,606.5	8,209,399	3.53	78.71
B.B.#4	407	155,428	53.0	55.1	93.3	10,534	COAL	71,120	23,022,000	1,637,321.4	5,597,979	3.60	78.71
B.B. IGNITION	-	-	-	-	-	-	LGT.OIL	5,214	5,738,010	29,918.0	683,246	-	131.04
B.B. COAL	**1,542**	**859,707**	**77.4**	**79.4**	**94.4**	**10,377**	-	-	-	-	**30,872,271**	**3.59**	-
B.B.C.T.#4 (GAS)	56	3,893	9.7	86.6	88.5	11,348	GAS	43,518	1,015,000	44,170.3	224,398	5.76	5.16
B.B.C.T.#4 (OIL)	56	40	0.1	86.6	42.0	5,147	LGT.OIL	35	5,737,985	203.3	4,644	11.61	132.69
B.B.C.T. #4 TOTAL	**56**	**3,933**	**9.8**	**86.6**	**87.5**	**11,282**	-	-	-	**44,373.6**	**229,042**	**5.82**	-
BIG BEND STATION TOTAL	**1,598**	**863,640**	**75.1**	**79.6**	**94.4**	**10,381**	-	-	-	**8,965,371.4**	**31,101,313**	**3.60**	-
POLK #1 GASIFIER	220	33,873	21.4	52.9	56.0	16,924	COAL	20,717	27,670,425	573,254.6	2,052,039	6.06	99.05
POLK #1 CT (GAS)	218	25,605	16.3	55.1	96.5	7,265	GAS	196,294	1,015,000	186,033.0	966,853	3.78	4.93
POLK #1 CT (OIL)	-	-	-	-	-	-	LGT.OIL	0	-	0.0	0	-	0.00
POLK #1 TOTAL	**220**	**59,478**	**37.5**	**55.1**	**68.1**	**12,766**	-	-	-	**759,287.6**	**3,018,892**	**5.08**	-
POLK #2 CT (GAS)	151	3,560	3.3	100.0	77.6	12,248	GAS	42,958	1,015,000	43,602.0	211,590	5.94	4.93
POLK #2 CT (OIL)	159	0	0.0	100.0	0.0	0	LGT.OIL	0	0	15,515.1	0	0.00	0.00
POLK #2 TOTAL	**151**	**3,560**	**3.3**	**100.0**	**77.6**	**12,248**	-	-	-	**59,117.1**	**211,590**	**5.94**	-
POLK #3 CT (GAS)	151	12,434	11.4	99.4	76.9	11,580	GAS	141,857	1,015,000	143,985.0	698,724	5.62	4.93
POLK #3 CT (OIL)	159	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**151**	**12,434**	**11.4**	**99.4**	**76.9**	**11,580**	-	-	-	**143,985.0**	**698,724**	**5.62**	-
POLK #4 (GAS)	**151**	**5,049**	**4.6**	**100.0**	**77.9**	**11,826**	GAS	**58,827**	**1,015,000**	**59,709.0**	**289,753**	**5.74**	**4.93**
POLK #5 (GAS)	**151**	**8,144**	**7.5**	**100.0**	**77.7**	**11,732**	GAS	**94,135**	**1,015,000**	**95,547.0**	**463,666**	**5.69**	**4.93**
POLK STATION TOTAL	**824**	**88,665**	**14.9**	**87.9**	**70.9**	**12,430**	-	-	-	**1,117,645.7**	**4,682,625**	**5.28**	-
COT 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	149	0.00	0.00
COT 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	149	0.00	0.00
CITY OF TAMPA TOTAL	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**298**	**0.00**	**0.00**
BAYSIDE ST 1	233	116,673	69.5	100.0	69.5	-	-	-	-	-	-	-	-
BAYSIDE CT1A	156	85,111	75.8	100.0	86.4	11,343	GAS	951,117	1,015,000	965,384.0	5,022,837	5.90	5.28
BAYSIDE CT1B	156	69,758	62.1	100.0	88.3	11,182	GAS	768,491	1,015,000	780,018.0	4,058,391	5.82	5.28
BAYSIDE CT1C	156	65,055	57.9	97.3	88.6	10,855	GAS	695,731	1,015,000	706,167.0	3,674,148	5.65	5.28
BAYSIDE UNIT 1 TOTAL	**701**	**336,597**	**66.7**	**99.1**	**66.7**	**7,283**	**GAS**	**2,415,339**	**1,015,000**	**2,451,569.0**	**12,755,376**	**3.79**	**5.28**
BAYSIDE ST 2	305	161,094	73.4	99.7	73.5	-	-	-	-	-	-	-	-
BAYSIDE CT2A	156	74,397	66.2	100.0	89.6	11,125	GAS	815,435	1,015,000	827,667.0	4,306,303	5.79	5.28
BAYSIDE CT2B	156	70,062	62.4	100.0	89.5	11,310	GAS	780,698	1,015,000	792,409.0	4,122,858	5.88	5.28
BAYSIDE CT2C	156	94,939	84.5	100.0	87.5	11,383	GAS	1,064,724	1,015,000	1,080,695.0	5,622,796	5.92	5.28
BAYSIDE CT2D	156	63,781	56.8	99.5	88.9	11,372	GAS	714,613	1,015,000	725,332.0	3,773,863	5.92	5.28
BAYSIDE UNIT 2 TOTAL	**929**	**464,273**	**69.4**	**99.7**	**69.6**	**7,380**	**GAS**	**3,375,470**	**1,015,000**	**3,426,103.0**	**17,825,820**	**3.84**	**5.28**
BAYSIDE UNIT 3 TOTAL	**56**	**725**	**1.8**	**100.0**	**89.7**	**11,691**	**GAS**	**8,351**	**1,015,000**	**8,476.0**	**44,100**	**6.08**	**5.28**
BAYSIDE UNIT 4 TOTAL	**56**	**1,095**	**2.7**	**100.0**	**90.2**	**11,288**	**GAS**	**12,177**	**1,015,000**	**12,360.0**	**64,308**	**5.87**	**5.28**
BAYSIDE UNIT 5 TOTAL	**56**	**1,560**	**3.9**	**100.0**	**93.5**	**11,373**	**GAS**	**17,480**	**1,015,000**	**17,742.0**	**92,311**	**5.92**	**5.28**
BAYSIDE UNIT 6 TOTAL	**56**	**998**	**2.5**	**100.0**	**88.7**	**11,281**	**GAS**	**11,092**	**1,015,000**	**11,258.0**	**58,575**	**5.87**	**5.28**
BAYSIDE STATION TOTAL	**1,854**	**805,248**	**60.3**	**99.5**	**68.4**	**7,361**	**GAS**	**5,839,909**	**1,015,000**	**5,927,508.0**	**30,840,490**	**3.83**	**5.28**
SYSTEM	**4,276**	**1,757,553**	**57.1**	**89.8**	**79.3**	**9,101**	-	-	-	**16,010,525.1**	**66,624,726**	**3.79**	-

Footnotes:
[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
COT = CITY OF TAMPA

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 11 of 25

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2013

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	244,170	85.2	85.1	94.9	10,104	COAL	105,290	23,430,430	2,466,990.0	8,244,713	3.38	78.30
2. B.B.#2	385	249,560	87.1	87.9	96.0	10,196	COAL	108,640	23,420,839	2,544,440.0	8,507,035	3.41	78.30
3. B.B.#3	365	233,570	86.0	88.0	95.5	10,453	COAL	104,210	23,429,325	2,441,570.0	8,160,145	3.49	78.30
4. B.B.#4	407	258,590	85.4	86.2	96.0	10,146	COAL	111,980	23,429,005	2,623,580.0	8,768,570	3.39	78.30
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	0.0	468,612	-	131.63
5. B.B. COAL	**1,542**	**985,890**	**85.9**	**86.8**	**95.6**	**10,221**	-	-	-	-	**34,149,075**	**3.46**	-
6. B.B.C.T.#4 OIL	56	10	0.0	-	3.6	300,000	LGT OIL	90	33,333,333	3,000.0	11,847	118.47	131.63
7. B.B.C.T.#4 GAS	56	2,330	5.6	-	99.1	10,966	GAS	24,850	1,028,169	25,550.0	137,649	5.91	5.54
8. B.B.C.T.#4 TOTAL	**56**	**2,340**	**5.6**	**99.4**	**88.9**	**12,201**	-	-	-	**28,550.0**	**149,496**	**6.39**	-
9. BIG BEND STATION TOTAL	**1,598**	**988,230**	**83.1**	**87.2**	**95.6**	**10,225**	-	-	-	**10,105,130.0**	**34,298,571**	**3.47**	-
10. POLK #1 GASIFIER	220	155,840	95.2	-	98.8	10,134	COAL	57,270	27,574,996	1,579,220.0	5,391,497	3.46	94.14
11. POLK #1 CT GAS	218	3,390	2.1	-	97.2	7,481	GAS	29,050	872,978	25,360.0	160,914	4.75	5.54
12. POLK #1 TOTAL	**220**	**159,230**	**97.3**	**92.4**	**98.8**	**10,077**	-	-	-	**1,604,580.0**	**5,552,411**	**3.49**	-
13. POLK #2 CT GAS	151	24,410	21.7	-	94.0	11,232	GAS	266,710	1,028,008	274,180.0	1,477,358	6.05	5.54
14. POLK #2 CT OIL	159	200	0.2	-	25.2	31,900	LGT OIL	1,100	5,800,000	6,380.0	140,824	70.41	128.02
15. POLK #2 TOTAL	**159**	**24,610**	**20.8**	**98.2**	**91.9**	**11,400**	-	-	-	**280,560.0**	**1,618,182**	**6.58**	-
16. POLK #3 CT GAS	151	20,850	18.6	-	95.2	11,239	GAS	227,960	1,027,987	234,340.0	1,262,716	6.06	5.54
17. POLK #3 CT OIL	159	200	0.2	-	25.2	31,900	LGT OIL	1,100	5,800,000	6,380.0	140,823	70.41	128.02
18. POLK #3 TOTAL	**159**	**21,050**	**17.8**	**98.2**	**92.8**	**11,436**	-	-	-	**240,720.0**	**1,403,539**	**6.67**	-
19. POLK #4 CT GAS	**151**	**18,480**	**16.4**	**98.8**	**97.9**	**11,082**	**GAS**	**199,210**	**1,028,011**	**204,790.0**	**1,103,464**	**5.97**	**5.54**
20. POLK #5 CT GAS	**151**	**13,650**	**12.2**	**98.9**	**99.3**	**10,997**	**GAS**	**146,020**	**1,028,010**	**150,110.0**	**808,834**	**5.93**	**5.54**
21. POLK STATION TOTAL	**840**	**237,020**	**37.9**	**96.9**	**97.4**	**10,466**	-	-	-	**2,480,760.0**	**10,486,430**	**4.42**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	246,420	47.2	89.1	57.8	7,367	GAS	1,766,020	1,028,001	1,815,470.0	9,782,334	3.97	5.54
24. BAYSIDE #2	929	374,120	54.1	89.0	59.6	7,356	GAS	2,677,230	1,027,999	2,752,190.0	14,829,706	3.96	5.54
25. BAYSIDE #3	56	4,020	9.6	98.6	97.0	10,950	GAS	42,830	1,027,784	44,020.0	237,244	5.90	5.54
26. BAYSIDE #4	56	3,400	8.2	98.6	97.9	10,994	GAS	36,370	1,027,770	37,380.0	201,461	5.93	5.54
27. BAYSIDE #5	56	5,320	12.8	98.6	95.0	11,026	GAS	57,060	1,028,041	58,660.0	316,067	5.94	5.54
28. BAYSIDE #6	56	4,550	10.9	98.6	96.7	10,969	GAS	48,550	1,028,012	49,910.0	268,928	5.91	5.54
29. BAYSIDE TOTAL	**1,854**	**637,830**	**46.2**	**90.2**	**59.5**	**7,459**	**GAS**	**4,628,060**	**1,027,997**	**4,757,630.0**	**25,635,740**	**4.02**	**5.54**
30. SYSTEM	**4,292**	**1,863,080**	**58.3**	**90.4**	**79.3**	**9,309**	-	-	-	**17,343,520.0**	**70,420,741**	**3.78**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil.
[3] City of Tampa on long term reserve standby.

[2] Fuel burned (MM BTU) system total excludes ignition oil.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2013

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	245,060	85.6	85.1	95.3	10,100	COAL	105,640	23,430,519	2,475,200.0	8,480,209	3.46	80.27
2. B.B.#2	385	250,540	87.5	87.9	96.4	10,192	COAL	109,030	23,419,151	2,553,390.0	8,752,345	3.49	80.27
3. B.B.#3	365	237,470	87.4	88.0	97.1	10,434	COAL	105,750	23,429,882	2,477,710.0	8,489,043	3.57	80.27
4. B.B.#4	407	259,820	85.8	86.2	96.4	10,141	COAL	112,460	23,429,308	2,634,860.0	9,027,685	3.47	80.27
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	0.0	470,681	-	132.21
5. B.B. COAL	**1,542**	**992,890**	**86.5**	**86.8**	**96.3**	**10,214**	-	-	-	-	**35,219,963**	**3.55**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	70	34,285,714	2,400.0	9,255	0.00	132.21
7. B.B.C.T.#4 GAS	56	1,590	3.8	-	94.6	11,340	GAS	17,550	1,027,350	18,030.0	99,625	6.27	5.68
8. B.B.C.T.#4 TOTAL	**56**	**1,590**	**3.8**	**99.4**	**83.5**	**12,849**	-	-	-	**20,430.0**	**108,880**	**6.85**	-
9. BIG BEND STATION TOTAL	**1,598**	**994,480**	**83.6**	**87.2**	**96.3**	**10,218**	-	-	-	**10,161,590.0**	**35,328,843**	**3.55**	-
10. POLK #1 GASIFIER	220	155,840	95.2	-	98.8	10,134	COAL	57,270	27,574,996	1,579,220.0	5,400,852	3.47	94.31
11. POLK #1 CT GAS	218	3,400	2.1	-	91.7	7,538	GAS	29,310	874,446	25,630.0	166,382	4.89	5.68
12. POLK #1 TOTAL	**220**	**159,240**	**97.3**	**92.4**	**98.6**	**10,078**	-	-	-	**1,604,850.0**	**5,567,234**	**3.50**	-
13. POLK #2 CT GAS	151	25,690	22.9	-	94.5	11,196	GAS	279,790	1,027,985	287,620.0	1,588,264	6.18	5.68
14. POLK #2 CT OIL	159	160	0.1	-	25.2	31,938	LGT OIL	890	5,741,573	5,110.0	114,321	71.45	128.45
15. POLK #2 TOTAL	**159**	**25,850**	**21.9**	**98.2**	**92.9**	**11,324**	-	-	-	**292,730.0**	**1,702,585**	**6.59**	-
16. POLK #3 CT GAS	151	18,730	16.7	-	96.9	11,188	GAS	203,850	1,028,011	209,560.0	1,157,180	6.18	5.68
17. POLK #3 CT OIL	159	160	0.1	-	25.2	31,938	LGT OIL	890	5,741,573	5,110.0	114,322	71.45	128.45
18. POLK #3 TOTAL	**159**	**18,890**	**16.0**	**98.2**	**94.6**	**11,364**	-	-	-	**214,670.0**	**1,271,502**	**6.73**	-
19. POLK #4 CT GAS	**151**	**16,610**	**14.8**	**98.8**	**98.2**	**11,118**	**GAS**	**179,640**	**1,028,000**	**184,670.0**	**1,019,749**	**6.14**	**5.68**
20. POLK #5 CT GAS	**151**	**11,290**	**10.0**	**98.9**	**98.4**	**11,177**	**GAS**	**122,750**	**1,028,024**	**126,190.0**	**696,806**	**6.17**	**5.68**
21. POLK STATION TOTAL	**840**	**231,880**	**37.1**	**96.9**	**97.6**	**10,450**	-	-	-	**2,423,110.0**	**10,257,876**	**4.42**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	253,850	48.7	89.1	59.0	7,353	GAS	1,815,600	1,028,007	1,866,450.0	10,306,483	4.06	5.68
24. BAYSIDE #2	929	396,910	57.4	89.0	63.2	7,332	GAS	2,830,790	1,027,999	2,910,050.0	16,069,337	4.05	5.68
25. BAYSIDE #3	56	3,840	9.2	98.6	93.9	11,052	GAS	41,290	1,027,852	42,440.0	234,388	6.10	5.68
26. BAYSIDE #4	56	2,790	6.7	98.6	94.0	11,197	GAS	30,390	1,027,970	31,240.0	172,513	6.18	5.68
27. BAYSIDE #5	56	5,920	14.2	98.6	93.6	11,051	GAS	63,630	1,028,131	65,420.0	361,204	6.10	5.68
28. BAYSIDE #6	56	4,250	10.2	98.6	93.7	11,092	GAS	45,860	1,027,911	47,140.0	260,330	6.13	5.68
29. BAYSIDE TOTAL	**1,854**	**667,560**	**48.4**	**90.2**	**62.0**	**7,434**	**GAS**	**4,827,560**	**1,028,002**	**4,962,740.0**	**27,404,255**	**4.11**	**5.68**
30. SYSTEM	**4,292**	**1,893,920**	**59.3**	**90.4**	**80.7**	**9,265**	-	-	-	**17,547,440.0**	**72,990,974**	**3.85**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2013

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	235,800	85.1	85.1	94.7	10,106	COAL	101,710	23,428,965	2,382,960.0	8,233,565	3.49	80.95
2. B.B.#2	385	240,120	86.6	87.9	95.5	10,201	COAL	104,590	23,420,690	2,449,570.0	8,466,707	3.53	80.95
3. B.B.#3	365	222,300	84.6	88.0	94.0	10,473	COAL	99,370	23,428,198	2,328,060.0	8,044,142	3.62	80.95
4. B.B.#4	407	248,650	84.9	86.2	95.5	10,151	COAL	107,730	23,429,685	2,524,080.0	8,720,895	3.51	80.95
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	0.0	472,708	-	132.78
5. B.B. COAL	**1,542**	**946,870**	**85.3**	**86.8**	**94.9**	**10,228**	-	-	-	-	**33,938,017**	**3.58**	-
6. B.B.C.T.#4 OIL	56	10	0.0	-	3.0	309,000	LGT OIL	100	30,900,000	3,090.0	16,478	164.78	164.78
7. B.B.C.T.#4 GAS	56	2,440	6.1	-	99.0	11,008	GAS	26,130	1,027,937	26,860.0	155,845	6.39	5.96
8. B.B.C.T.#4 TOTAL	**56**	**2,450**	**6.1**	**99.4**	**87.5**	**12,224**	-	-	-	**29,950.0**	**172,323**	**7.03**	-
9. BIG BEND STATION TOTAL	**1,598**	**949,320**	**82.5**	**87.2**	**94.9**	**10,233**	-	-	-	**9,714,620.0**	**34,110,340**	**3.59**	-
10. POLK #1 GASIFIER	220	150,810	95.2	-	98.8	10,135	COAL	55,430	27,575,501	1,528,510.0	5,145,237	3.41	92.82
11. POLK #1 CT GAS	218	3,090	2.0	-	88.6	7,485	GAS	26,880	860,491	23,130.0	160,318	5.19	5.96
12. POLK #1 TOTAL	**220**	**153,900**	**97.2**	**92.4**	**98.5**	**10,082**	-	-	-	**1,551,640.0**	**5,305,555**	**3.45**	-
13. POLK #2 CT GAS	151	22,940	21.1	-	96.8	11,108	GAS	247,870	1,027,999	254,810.0	1,478,353	6.44	5.96
14. POLK #2 CT OIL	159	210	0.2	-	26.4	30,619	LGT OIL	1,110	5,792,793	6,430.0	143,167	68.17	128.98
15. POLK #2 TOTAL	**159**	**23,150**	**20.2**	**98.2**	**94.5**	**11,285**	-	-	-	**261,240.0**	**1,621,520**	**7.00**	-
16. POLK #3 CT GAS	151	16,450	15.1	-	98.1	11,092	GAS	177,490	1,028,002	182,460.0	1,058,591	6.44	5.96
17. POLK #3 CT OIL	159	210	0.2	-	26.4	30,619	LGT OIL	1,110	5,792,793	6,430.0	143,167	68.17	128.98
18. POLK #3 TOTAL	**159**	**16,660**	**14.6**	**98.2**	**94.9**	**11,338**	-	-	-	**188,890.0**	**1,201,758**	**7.21**	-
19. POLK #4 CT GAS	**151**	**17,180**	**15.8**	**98.8**	**98.9**	**10,997**	**GAS**	**183,780**	**1,028,023**	**188,930.0**	**1,096,106**	**6.38**	**5.96**
20. POLK #5 CT GAS	**151**	**13,390**	**12.3**	**98.9**	**99.6**	**10,992**	**GAS**	**143,170**	**1,028,009**	**147,180.0**	**853,898**	**6.38**	**5.96**
21. POLK STATION TOTAL	**840**	**224,280**	**37.1**	**96.9**	**97.9**	**10,424**	-	-	-	**2,337,880.0**	**10,078,837**	**4.49**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	208,670	41.3	89.1	53.4	7,398	GAS	1,501,650	1,028,003	1,543,700.0	8,956,182	4.29	5.96
24. BAYSIDE #2	929	348,130	52.0	89.0	57.3	7,367	GAS	2,494,720	1,027,995	2,564,560.0	14,879,078	4.27	5.96
25. BAYSIDE #3	56	4,210	10.4	98.6	96.4	11,010	GAS	45,090	1,027,944	46,350.0	268,927	6.39	5.96
26. BAYSIDE #4	56	3,550	8.8	98.6	97.5	10,989	GAS	37,950	1,027,931	39,010.0	226,342	6.38	5.96
27. BAYSIDE #5	56	5,900	14.6	98.6	95.8	10,969	GAS	62,950	1,028,118	64,720.0	375,448	6.36	5.96
28. BAYSIDE #6	56	4,960	12.3	98.6	96.3	10,974	GAS	52,950	1,027,951	54,430.0	315,806	6.37	5.96
29. BAYSIDE TOTAL	**1,854**	**575,420**	**43.1**	**90.2**	**56.6**	**7,495**	**GAS**	**4,195,310**	**1,027,998**	**4,312,770.0**	**25,021,783**	**4.35**	**5.96**
30. SYSTEM	**4,292**	**1,749,020**	**56.6**	**90.4**	**77.8**	**9,357**	-	-	-	**16,365,270.0**	**69,210,960**	**3.96**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2013

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	241,910	84.5	85.1	94.1	10,113	COAL	104,420	23,429,324	2,446,490.0	8,413,381	3.48	80.57
2. B.B.#2	385	246,000	85.9	87.9	94.7	10,214	COAL	107,280	23,420,582	2,512,560.0	8,643,816	3.51	80.57
3. B.B.#3	365	153,150	56.4	59.6	92.4	10,492	COAL	68,580	23,430,300	1,606,850.0	5,525,664	3.61	80.57
4. B.B.#4	407	205,340	67.8	69.5	94.5	10,165	COAL	89,080	23,430,400	2,087,180.0	7,177,400	3.50	80.57
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,450	-	0.0	593,861	-	133.45
5. B.B. COAL	**1,542**	**846,400**	**73.8**	**75.6**	**94.0**	**10,223**	-	-	-	-	**30,354,122**	**3.59**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	70	34,285,714	2,400.0	9,342	0.00	133.46
7. B.B.C.T.#4 GAS	56	710	1.7	-	97.5	10,958	GAS	7,570	1,027,741	7,780.0	45,988	6.48	6.08
8. B.B.C.T.#4 TOTAL	**56**	**710**	**1.7**	**99.4**	**74.6**	**14,338**	-	-	-	**10,180.0**	**55,330**	**7.79**	-
9. BIG BEND STATION TOTAL	**1,598**	**847,110**	**71.3**	**76.5**	**94.0**	**10,227**	-	-	-	**8,663,260.0**	**30,409,452**	**3.59**	-
10. POLK #1 GASIFIER	220	130,730	79.9	-	98.7	10,177	COAL	48,060	27,681,856	1,330,390.0	4,413,140	3.38	91.83
11. POLK #1 CT GAS	218	5,730	3.5	-	93.9	7,717	GAS	51,760	854,328	44,220.0	314,446	5.49	6.08
12. POLK #1 TOTAL	**220**	**136,460**	**83.4**	**77.5**	**98.5**	**10,073**	-	-	-	**1,374,610.0**	**4,727,586**	**3.46**	-
13. POLK #2 CT GAS	151	11,660	10.4	-	86.8	11,596	GAS	131,540	1,027,900	135,210.0	799,117	6.85	6.08
14. POLK #2 CT OIL	159	160	0.1	-	25.2	31,938	LGT OIL	890	5,741,573	5,110.0	115,165	71.98	129.40
15. POLK #2 TOTAL	**159**	**11,820**	**10.0**	**98.2**	**84.0**	**11,871**	-	-	-	**140,320.0**	**914,282**	**7.74**	-
16. POLK #3 CT GAS	151	8,410	7.5	-	91.3	11,451	GAS	93,680	1,027,968	96,300.0	569,114	6.77	6.08
17. POLK #3 CT OIL	159	160	0.1	-	25.2	31,938	LGT OIL	890	5,741,573	5,110.0	115,165	71.98	129.40
18. POLK #3 TOTAL	**159**	**8,570**	**7.2**	**98.2**	**87.0**	**11,833**	-	-	-	**101,410.0**	**684,279**	**7.98**	-
19. POLK #4 CT GAS	**151**	**6,070**	**5.4**	**57.4**	**91.4**	**11,328**	**GAS**	**66,890**	**1,027,956**	**68,760.0**	**406,362**	**6.69**	**6.08**
20. POLK #5 CT GAS	**151**	**4,650**	**4.1**	**86.1**	**96.2**	**11,292**	**GAS**	**51,080**	**1,027,995**	**52,510.0**	**310,315**	**6.67**	**6.08**
21. POLK STATION TOTAL	**840**	**167,570**	**26.8**	**83.3**	**96.3**	**10,369**	-	-	-	**1,737,610.0**	**7,042,824**	**4.20**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	212,700	40.8	89.1	55.6	7,404	GAS	1,531,840	1,027,999	1,574,730.0	9,306,054	4.38	6.08
24. BAYSIDE #2	929	373,780	54.1	89.0	59.5	7,342	GAS	2,669,550	1,028,005	2,744,310.0	16,217,736	4.34	6.08
25. BAYSIDE #3	56	2,190	5.3	98.6	93.1	11,279	GAS	24,020	1,028,310	24,700.0	145,923	6.66	6.08
26. BAYSIDE #4	56	1,530	3.7	98.6	94.2	11,451	GAS	17,050	1,027,566	17,520.0	103,580	6.77	6.08
27. BAYSIDE #5	56	3,880	9.3	98.6	91.2	11,224	GAS	42,370	1,027,850	43,550.0	257,401	6.63	6.08
28. BAYSIDE #6	56	2,920	7.0	98.6	93.1	11,216	GAS	31,850	1,028,257	32,750.0	193,491	6.63	6.08
29. BAYSIDE TOTAL	**1,854**	**597,000**	**43.3**	**90.2**	**58.4**	**7,433**	**GAS**	**4,316,680**	**1,028,003**	**4,437,560.0**	**26,224,185**	**4.39**	**6.08**
30. SYSTEM	**4,292**	**1,611,680**	**50.5**	**83.7**	**76.9**	**9,207**	-	-	-	**14,838,430.0**	**63,676,461**	**3.95**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil.
[3] City of Tampa on long term reserve standby.

[2] Fuel burned (MM BTU) system total excludes ignition oil.

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 15 of 25

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2013

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	227,360	82.0	85.1	91.3	10,149	COAL	98,480	23,430,240	2,307,410.0	7,859,254	3.46	79.81
2. B.B.#2	385	227,160	81.9	87.9	90.4	10,282	COAL	99,730	23,420,134	2,335,690.0	7,959,006	3.50	79.81
3. B.B.#3	365	209,370	79.7	88.0	88.5	10,547	COAL	94,250	23,429,496	2,208,230.0	7,521,674	3.59	79.81
4. B.B.#4	407	206,210	70.4	74.7	91.3	10,211	COAL	89,870	23,429,064	2,105,570.0	7,172,128	3.48	79.81
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	5,340	-	0.0	716,563	-	134.19
5. B.B. COAL	**1,542**	**870,100**	**78.4**	**83.7**	**90.4**	**10,294**	**-**	**-**	**-**	**-**	**31,228,625**	**3.59**	**-**
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	70	34,285,714	2,400.0	9,393	0.00	134.19
7. B.B.C.T.#4 GAS	56	710	1.8	-	90.6	11,592	GAS	8,010	1,027,466	8,230.0	53,544	7.54	6.68
8. B.B.C.T.#4 TOTAL	**56**	**710**	**1.8**	**99.4**	**70.4**	**14,972**	**-**	**-**	**-**	**10,630.0**	**62,937**	**8.86**	**-**
9. BIG BEND STATION TOTAL	**1,598**	**870,810**	**75.7**	**84.3**	**90.3**	**10,298**	**-**	**-**	**-**	**8,967,530.0**	**31,291,562**	**3.59**	**-**
10. POLK #1 GASIFIER	220	150,780	95.2	-	98.8	10,136	COAL	55,430	27,571,351	1,528,280.0	5,044,971	3.35	91.02
11. POLK #1 CT GAS	218	2,400	1.5	-	100.1	7,546	GAS	22,000	823,182	18,110.0	147,063	6.13	6.68
12. POLK #1 TOTAL	**220**	**153,180**	**96.7**	**92.4**	**98.8**	**10,095**	**-**	**-**	**-**	**1,546,390.0**	**5,192,034**	**3.39**	**-**
13. POLK #2 CT GAS	151	14,140	13.0	-	91.8	11,253	GAS	154,790	1,027,973	159,120.0	1,034,722	7.32	6.68
14. POLK #2 CT OIL	159	170	0.1	-	26.7	30,294	LGT OIL	890	5,786,517	5,150.0	115,531	67.96	129.81
15. POLK #2 TOTAL	**159**	**14,310**	**12.5**	**98.2**	**89.2**	**11,479**	**-**	**-**	**-**	**164,270.0**	**1,150,253**	**8.04**	**-**
16. POLK #3 CT GAS	151	8,710	8.0	-	93.0	11,269	GAS	95,480	1,027,964	98,150.0	638,253	7.33	6.68
17. POLK #3 CT OIL	159	170	0.1	-	26.7	30,294	LGT OIL	890	5,786,517	5,150.0	115,531	67.96	129.81
18. POLK #3 TOTAL	**159**	**8,880**	**7.8**	**98.2**	**88.8**	**11,633**	**-**	**-**	**-**	**103,300.0**	**753,784**	**8.49**	**-**
19. POLK #4 CT GAS	**151**	**6,840**	**6.3**	**75.8**	**98.5**	**11,057**	**GAS**	**73,570**	**1,028,001**	**75,630.0**	**491,792**	**7.19**	**6.68**
20. POLK #5 CT GAS	**151**	**3,540**	**3.3**	**98.9**	**97.7**	**11,014**	**GAS**	**37,920**	**1,028,217**	**38,990.0**	**253,483**	**7.16**	**6.68**
21. POLK STATION TOTAL	**840**	**186,750**	**30.9**	**92.8**	**97.4**	**10,327**	**-**	**-**	**-**	**1,928,580.0**	**7,841,346**	**4.20**	**-**
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	113,100	22.4	68.3	51.1	7,449	GAS	819,520	1,028,004	842,470.0	5,478,229	4.84	6.68
24. BAYSIDE #2	929	146,910	22.0	68.2	31.5	7,593	GAS	1,085,130	1,028,006	1,115,520.0	7,253,747	4.94	6.68
25. BAYSIDE #3	56	2,770	6.9	98.6	89.9	11,235	GAS	30,270	1,028,081	31,120.0	202,345	7.30	6.68
26. BAYSIDE #4	56	1,620	4.0	98.6	90.4	11,444	GAS	18,030	1,028,286	18,540.0	120,525	7.44	6.68
27. BAYSIDE #5	56	4,530	11.2	98.6	89.9	11,174	GAS	49,240	1,028,026	50,620.0	329,154	7.27	6.68
28. BAYSIDE #6	56	3,600	8.9	98.6	90.5	11,175	GAS	39,140	1,027,849	40,230.0	261,638	7.27	6.68
29. BAYSIDE TOTAL	**1,854**	**272,530**	**20.4**	**71.9**	**38.8**	**7,700**	**GAS**	**2,041,330**	**1,028,006**	**2,098,500.0**	**13,645,638**	**5.01**	**6.68**
30. SYSTEM	**4,292**	**1,330,090**	**43.0**	**80.6**	**71.6**	**9,770**	**-**	**-**	**-**	**12,994,610.0**	**52,778,546**	**3.97**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil.
[2] Fuel burned (MM BTU) system total excludes ignition oil.
[3] City of Tampa on long term reserve standby.

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 1, Page 16 of 25

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2013

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	B.B.#1	395	160,310	54.5	57.7	89.6	10,066	COAL	68,870	23,429,940	1,613,620.0	5,505,537	3.43	79.94
2.	B.B.#2	395	159,360	54.2	59.5	88.3	10,265	COAL	69,840	23,421,535	1,635,760.0	5,583,079	3.50	79.94
3.	B.B.#3	365	218,610	80.5	88.0	89.4	10,498	COAL	97,960	23,428,032	2,295,010.0	7,831,024	3.58	79.94
4.	B.B.#4	417	252,670	81.4	86.2	91.5	10,138	COAL	109,330	23,430,074	2,561,610.0	8,739,966	3.46	79.94
	B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,560	-	0.0	479,352	-	134.65
5.	**B.B. COAL**	**1,572**	**790,950**	**67.6**	**72.7**	**89.9**	**10,248**	-	-	-	-	**28,138,958**	**3.56**	-
6.	B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	30	71,666,667	2,150.0	7,239	0.00	241.30
7.	B.B.C.T.#4 GAS	61	170	0.4	-	92.9	11,588	GAS	1,920	1,026,042	1,970.0	12,177	7.16	6.34
8.	**B.B.C.T.#4 TOTAL**	**61**	**170**	**0.4**	**99.4**	**39.8**	**24,235**	-	-	-	**4,120.0**	**19,416**	**11.42**	-
9.	**BIG BEND STATION TOTAL**	**1,633**	**791,120**	**65.1**	**73.7**	**89.9**	**10,251**	-	-	-	**8,110,120.0**	**28,158,374**	**3.56**	-
10.	POLK #1 GASIFIER	220	155,710	95.1	-	98.7	10,137	COAL	57,240	27,574,423	1,578,360.0	5,158,051	3.31	90.11
11.	POLK #1 CT GAS	235	3,100	1.8	-	87.9	7,316	GAS	26,440	857,791	22,680.0	167,693	5.41	6.34
12.	**POLK #1 TOTAL**	**220**	**158,810**	**97.0**	**92.4**	**98.5**	**10,081**	-	-	-	**1,601,040.0**	**5,325,744**	**3.35**	-
13.	POLK #2 CT GAS	183	1,260	0.9	-	98.4	10,786	GAS	13,220	1,027,988	13,590.0	83,847	6.65	6.34
14.	POLK #2 CT OIL	187	170	0.1	-	18.2	36,529	LGT OIL	1,070	5,803,738	6,210.0	139,408	82.00	130.29
15.	**POLK #2 TOTAL**	**187**	**1,430**	**1.0**	**98.2**	**64.5**	**13,846**	-	-	-	**19,800.0**	**223,255**	**15.61**	-
16.	POLK #3 CT GAS	183	720	0.5	-	98.4	11,083	GAS	7,770	1,027,027	7,980.0	49,280	6.84	6.34
17.	POLK #3 CT OIL	187	170	0.1	-	18.2	36,529	LGT OIL	1,070	5,803,738	6,210.0	139,408	82.00	130.29
18.	**POLK #3 TOTAL**	**187**	**890**	**0.6**	**98.2**	**53.4**	**15,944**	-	-	-	**14,190.0**	**188,688**	**21.20**	-
19.	**POLK #4 CT GAS**	**183**	**550**	**0.4**	**98.8**	**75.1**	**12,000**	**GAS**	**6,420**	**1,028,037**	**6,600.0**	**40,718**	**7.40**	**6.34**
20.	**POLK #5 CT GAS**	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21.	**POLK STATION TOTAL**	**960**	**161,680**	**22.6**	**78.3**	**97.5**	**10,154**	-	-	-	**1,641,630.0**	**5,778,405**	**3.57**	-
22.	**CITY OF TAMPA GAS** [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23.	BAYSIDE #1	792	230,940	39.2	89.1	50.2	7,276	GAS	1,634,620	1,028,000	1,680,390.0	10,367,406	4.49	6.34
24.	BAYSIDE #2	1,047	211,790	27.2	89.0	29.9	7,348	GAS	1,513,780	1,028,003	1,556,170.0	9,600,991	4.53	6.34
25.	BAYSIDE #3	61	660	1.5	98.6	90.2	11,015	GAS	7,080	1,026,836	7,270.0	44,904	6.80	6.34
26.	BAYSIDE #4	61	340	0.7	98.6	92.9	11,294	GAS	3,730	1,029,491	3,840.0	23,657	6.96	6.34
27.	BAYSIDE #5	61	1,500	3.3	98.6	87.8	11,047	GAS	16,120	1,027,916	16,570.0	102,239	6.82	6.34
28.	BAYSIDE #6	61	1,140	2.5	98.6	89.0	11,009	GAS	12,210	1,027,846	12,550.0	77,441	6.79	6.34
29.	**BAYSIDE TOTAL**	**2,083**	**446,370**	**28.8**	**90.2**	**38.1**	**7,341**	**GAS**	**3,187,540**	**1,028,000**	**3,276,790.0**	**20,216,638**	**4.53**	**6.34**
30.	**SYSTEM**	**4,676**	**1,399,170**	**40.2**	**82.0**	**63.1**	**9,312**	-	-	-	**13,028,540.0**	**54,153,417**	**3.87**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil.
[2] City of Tampa on long term reserve standby.

[2] Fuel burned (MM BTU) system total excludes ignition oil.

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

SCHEDULE E5

	ACTUAL					
	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0
5. BURNED:						
6. UNITS (BBL)	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0
9. ENDING INVENTORY:						
10. UNITS (BBL)	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	4,114	4,112	7,839	15,848	2,031	7,937
16. UNIT COST ($/BBL)	134.75	139.82	133.47	130.78	127.96	131.04
17. AMOUNT ($)	554,369	574,940	1,046,235	2,072,605	259,879	1,040,085
18. BURNED:						
19. UNITS (BBL)	4,547	4,479	5,852	1,594	(174)	35
20. UNIT COST ($/BBL)	125.27	125.88	126.90	127.68	127.30	132.69
21. AMOUNT ($)	569,602	563,813	742,615	203,514	(22,150)	4,644
22. ENDING INVENTORY:						
23. UNITS (BBL)	87,858	81,679	80,534	92,470	89,237	91,441
24. UNIT COST ($/BBL)	128.05	128.59	129.09	129.35	129.20	129.25
25. AMOUNT ($)	11,250,083	10,503,113	10,395,929	11,960,722	11,529,472	11,818,390
26. DAYS SUPPLY: NORMAL	534	529	556	675	670	711
27. DAYS SUPPLY: EMERGENCY	13	12	12	13	13	13
COAL						
28. PURCHASES:						
29. UNITS (TONS)	311,846	375,022	369,305	385,367	434,658	446,873
30. UNIT COST ($/TON)	77.85	85.69	79.32	78.40	82.76	79.16
31. AMOUNT ($)	24,275,805	32,136,440	29,294,228	30,214,103	35,973,005	35,373,852
32. BURNED:						
33. UNITS (TONS)	298,817	220,243	391,806	335,418	374,633	404,256
34. UNIT COST ($/TON)	81.87	73.72	76.68	73.49	85.22	81.44
35. AMOUNT ($)	24,464,225	16,236,277	30,045,365	24,651,021	31,926,565	32,924,310
36. ENDING INVENTORY:						
37. UNITS (TONS)	423,201	577,980	555,479	605,428	665,453	708,070
38. UNIT COST ($/TON)	82.50	84.97	83.36	82.26	83.82	83.32
39. AMOUNT ($)	34,914,416	49,110,792	46,303,004	49,802,988	55,778,515	58,999,447
40. DAYS SUPPLY:	34	54	49	48	47	47
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	4,255,002	5,266,523	3,845,336	4,669,607	5,516,597	6,310,216
43. UNIT COST ($/MCF)	5.24	4.74	5.20	5.56	5.46	5.25
44. AMOUNT ($)	22,311,102	24,981,251	19,981,322	25,955,920	30,104,892	33,112,162
45. BURNED:						
46. UNITS (MCF)	4,287,064	5,283,555	3,706,166	4,801,870	5,399,416	6,417,498
47. UNIT COST ($/MCF)	5.26	4.73	5.13	5.47	5.50	5.25
48. AMOUNT ($)	22,541,390	24,997,687	19,019,935	26,251,482	29,693,271	33,695,772
49. ENDING INVENTORY:						
50. UNITS (MCF)	764,865	747,833	887,003	754,740	871,921	764,639
51. UNIT COST ($/MCF)	3.34	3.40	3.95	4.25	4.15	3.97
52. AMOUNT ($)	2,557,451	2,541,015	3,502,402	3,206,840	3,618,461	3,034,851
53. DAYS SUPPLY:	5	5	6	5	6	5
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2013 THROUGH DECEMBER 2013

SCHEDULE E5

	Estimated						
	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	0	0	0	0	0	0	0
3. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. AMOUNT ($)	0	0	0	0	0	0	0
5. BURNED:							
6. UNITS (BBL)	0	0	0	0	0	0	0
7. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. AMOUNT ($)	0	0	0	0	0	0	0
9. ENDING INVENTORY:							
10. UNITS (BBL)	0	0	0	0	0	0	0
11. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. AMOUNT ($)	0	0	0	0	0	0	0
13. DAYS SUPPLY:	0	0	0	0	0	0	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	5,850	5,410	5,880	6,300	7,190	5,730	78,241
16. UNIT COST ($/BBL)	139.30	139.52	139.88	140.20	140.39	140.52	135.97
17. AMOUNT ($)	814,907	754,804	822,490	883,276	1,009,423	805,159	10,638,172
18. BURNED:							
19. UNITS (BBL)	5,850	5,410	5,880	6,300	7,190	5,730	52,693
20. UNIT COST ($/BBL)	50.17	43.97	51.50	38.04	33.44	49.92	69.50
21. AMOUNT ($)	293,494	237,898	302,812	239,672	240,455	286,055	3,662,424
22. ENDING INVENTORY:							
23. UNITS (BBL)	91,441	91,441	91,441	91,441	91,441	91,441	91,441
24. UNIT COST ($/BBL)	129.82	130.33	130.88	131.42	131.99	132.46	132.46
25. AMOUNT ($)	11,871,192	11,917,417	11,967,585	12,017,327	12,069,732	12,112,684	12,112,684
26. DAYS SUPPLY: NORMAL	492	498	511	532	555	546	-
27. DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	377,000	404,000	511,000	430,000	400,000	434,000	4,879,071
30. UNIT COST ($/TON)	79.29	82.29	81.18	80.60	80.50	80.50	80.69
31. AMOUNT ($)	29,892,128	33,245,539	41,484,220	34,658,033	32,199,335	34,938,328	393,685,016
32. BURNED:							
33. UNITS (TONS)	487,390	490,150	468,830	417,420	437,760	403,240	4,729,963
34. UNIT COST ($/TON)	81.13	82.87	83.36	83.29	82.86	82.57	81.15
35. AMOUNT ($)	39,540,572	40,620,815	39,083,254	34,767,262	36,273,596	33,297,009	383,830,271
36. ENDING INVENTORY:							
37. UNITS (TONS)	597,680	511,530	553,700	566,280	528,520	559,280	559,280
38. UNIT COST ($/TON)	83.55	84.40	83.37	82.58	82.34	81.87	81.87
39. AMOUNT ($)	49,935,014	43,172,818	46,161,891	46,761,922	43,519,623	45,787,693	45,787,693
40. DAYS SUPPLY:	38	34	38	42	37	42	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	5,729,983	5,660,450	5,000,630	4,719,200	2,189,910	3,243,310	56,406,764
43. UNIT COST ($/MCF)	5.54	5.68	5.96	6.08	6.97	6.38	5.58
44. AMOUNT ($)	31,756,425	32,152,261	29,821,094	28,681,527	15,256,995	20,691,553	314,806,504
45. BURNED:							
46. UNITS (MCF)	5,521,860	5,660,450	5,000,630	4,719,200	2,433,100	3,243,310	56,474,119
47. UNIT COST ($/MCF)	5.54	5.68	5.96	6.08	6.68	6.34	5.56
48. AMOUNT ($)	30,586,675	32,132,261	29,824,894	28,669,527	16,264,495	20,570,353	314,247,742
49. ENDING INVENTORY:							
50. UNITS (MCF)	972,762	972,762	972,762	972,762	729,572	729,572	729,572
51. UNIT COST ($/MCF)	4.32	4.34	4.34	4.35	4.42	4.59	4.59
52. AMOUNT ($)	4,204,600	4,224,600	4,220,800	4,232,800	3,225,300	3,346,500	3,346,500
53. DAYS SUPPLY:	7	7	7	7	5	5	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
POWER SOLD
ACTUAL FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
			TYPE	TOTAL	WHEELED FROM	MWH	(A)	(B)	TOTAL $		GAINS ON
MONTH	SOLD TO		& SCHEDULE	MWH SOLD	OTHER SYSTEMS	FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST	MARKET BASED SALES
ACTUAL											
Jan-13	SEMINOLE	JURISD.	SCH. - D	484.0	0.0	484.0	2.448	2.693	11,847.62	13,032.38	615.37
	VARIOUS	JURISD.	SCH. - C	205.0	0.0	205.0	2.150	2.606	4,406.72	5,341.98	818.41
	VARIOUS	JURISD.	SCH. - CB	490.0	0.0	490.0	2.159	2.429	10,577.83	11,900.76	968.76
	VARIOUS	JURISD.	SCH. - MA	996.0	0.0	996.0	2.358	2.939	23,487.62	29,276.77	5,260.74
	TOTAL			**2,175.0**	**0.0**	**2,175.0**	**2.314**	**2.738**	**50,319.79**	**59,551.89**	**7,663.28**
ACTUAL											
Feb-13	SEMINOLE	JURISD.	SCH. - D	574.3	0.0	574.3	2.265	2.492	13,009.03	14,309.93	(838.06)
	VARIOUS	JURISD.	SCH. - C	1,684.0	0.0	1,684.0	2.190	2.573	36,878.66	43,335.32	5,404.66
	VARIOUS	JURISD.	SCH. - CB	2,838.0	0.0	2,838.0	2.305	2.635	65,405.30	74,793.65	6,375.51
	VARIOUS	JURISD.	SCH. - MA	2,626.0	0.0	2,626.0	2.347	3.056	61,628.39	80,239.76	16,748.28
	TOTAL			**7,722.3**	**0.0**	**7,722.3**	**2.291**	**2.754**	**176,921.38**	**212,678.66**	**27,690.39**
ACTUAL											
Mar-13	SEMINOLE	JURISD.	SCH. - D	1,053.3	0.0	1,053.3	2.624	2.886	27,636.05	30,399.66	1,784.38
	VARIOUS	JURISD.	SCH. - C	682.0	0.0	682.0	2.387	2.735	16,280.67	18,655.26	1,775.17
	VARIOUS	JURISD.	SCH. - CB	23,348.0	0.0	23,348.0	2.717	3.114	634,278.82	727,094.77	61,626.25
	VARIOUS	JURISD.	SCH. - MA	5,803.0	0.0	5,803.0	2.716	3.497	157,593.87	202,956.55	39,872.53
	TOTAL			**30,886.3**	**0.0**	**30,886.3**	**2.706**	**3.170**	**835,789.41**	**979,106.24**	**105,058.33**
ACTUAL											
Apr-13	SEMINOLE	JURISD.	SCH. - D	1,138.0	0.0	1,138.0	3.196	3.516	36,375.13	40,012.64	2,852.90
	VARIOUS	JURISD.	SCH. - C	1,039.0	0.0	1,039.0	2.668	3.253	27,720.87	33,797.06	5,698.89
	VARIOUS	JURISD.	SCH. - CB	27,373.0	0.0	27,373.0	3.144	3.597	860,502.47	984,639.10	87,443.19
	VARIOUS	JURISD.	SCH. - MA	7,184.0	0.0	7,184.0	2.743	3.612	197,030.10	259,488.16	56,190.56
	TOTAL			**36,734.0**	**0.0**	**36,734.0**	**3.053**	**3.588**	**1,121,628.57**	**1,317,936.96**	**152,185.54**
ACTUAL											
May-13	SEMINOLE	JURISD.	SCH. - D	964.7	0.0	964.7	2.923	3.216	28,202.07	31,022.28	2,091.15
	VARIOUS	JURISD.	SCH. - C	189.0	0.0	189.0	2.558	3.169	4,834.59	5,990.24	1,106.51
	VARIOUS	JURISD.	SCH. - CB	19,615.0	0.0	19,615.0	3.181	3.661	623,859.05	718,139.02	60,871.66
	VARIOUS	JURISD.	SCH. - MA	13,129.0	0.0	13,129.0	3.187	4.472	418,392.77	587,192.51	149,793.59
	TOTAL			**33,897.7**	**0.0**	**33,897.7**	**3.172**	**3.960**	**1,075,288.48**	**1,342,344.05**	**213,862.91**
ACTUAL											
Jun-13	SEMINOLE	JURISD.	SCH. - D	892.5	0.0	892.5	2.930	3.223	26,146.35	28,760.99	1,996.81
	VARIOUS	JURISD.	SCH. - C	49.0	0.0	49.0	2.603	3.465	1,275.28	1,697.61	380.79
	VARIOUS	JURISD.	SCH. - CB	15,143.0	0.0	15,143.0	3.229	3.692	488,897.18	559,022.83	49,188.17
	VARIOUS	JURISD.	SCH. - MA	1,819.0	0.0	1,819.0	2.800	3.406	50,924.31	61,946.10	10,186.66
	TOTAL			**17,903.5**	**0.0**	**17,903.5**	**3.168**	**3.639**	**567,243.12**	**651,427.53**	**61,752.43**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2013 THROUGH DECEMBER 2013

SCHEDULE E6

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
ESTIMATED											
Jul-13	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.415	3.555	34,490.00	35,907.00	1,417.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	8,190.0	0.0	8,190.0	4.167	4.585	341,311.32	375,480.00	34,168.68
	TOTAL			**9,200.0**	**0.0**	**9,200.0**	**4.085**	**4.472**	**375,801.32**	**411,387.00**	**35,585.68**
ESTIMATED											
Aug-13	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	3.454	3.595	34,890.00	36,307.00	1,417.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	8,080.0	0.0	8,080.0	4.027	4.430	325,403.82	357,980.00	32,576.18
	TOTAL			**9,090.0**	**0.0**	**9,090.0**	**3.964**	**4.338**	**360,293.82**	**394,287.00**	**33,993.18**
ESTIMATED											
Sep-13	SEMINOLE	JURISD.	SCH. - D	1,000.0	0.0	1,000.0	3.539	3.681	35,390.00	36,807.00	1,417.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	7,920.0	0.0	7,920.0	4.306	4.737	341,011.35	375,150.00	34,138.65
	TOTAL			**8,920.0**	**0.0**	**8,920.0**	**4.220**	**4.618**	**376,401.35**	**411,957.00**	**35,555.65**
ESTIMATED											
Oct-13	SEMINOLE	JURISD.	SCH. - D	730.0	0.0	730.0	3.532	3.726	25,780.00	27,197.00	1,417.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	10,180.0	0.0	10,180.0	3.826	4.209	389,497.41	428,490.00	38,992.59
	TOTAL			**10,910.0**	**0.0**	**10,910.0**	**3.806**	**4.177**	**415,277.41**	**455,687.00**	**40,409.59**
ESTIMATED											
Nov-13	SEMINOLE	JURISD.	SCH. - D	650.0	0.0	650.0	3.366	3.584	21,880.00	23,297.00	1,417.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	10,090.0	0.0	10,090.0	3.667	4.034	370,017.54	407,060.00	37,042.46
	TOTAL			**10,740.0**	**0.0**	**10,740.0**	**3.649**	**4.007**	**391,897.54**	**430,357.00**	**38,459.46**
ESTIMATED											
Dec-13	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	3.291	3.536	19,090.00	20,507.55	1,417.55
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	14,550.0	0.0	14,550.0	3.367	3.704	489,878.28	538,920.00	49,041.72
	TOTAL			**15,130.0**	**0.0**	**15,130.0**	**3.364**	**3.697**	**508,968.28**	**559,427.55**	**50,459.27**
TOTAL	SEMINOLE	JURISD.	SCH. - D	10,086.8	0.0	10,086.8	3.120	3.347	314,736.25	337,560.43	17,005.10
Jan-13	VARIOUS	JURISD.	SCH. - C	3,848.0	0.0	3,848.0	2.375	2.828	91,396.79	108,817.47	15,184.43
THRU	VARIOUS	JURISD.	SCH. - CB	88,807.0	0.0	88,807.0	3.022	3.463	2,683,520.65	3,075,590.13	266,473.54
Dec-13	VARIOUS	JURISD.	SCH. - MA	90,567.0	0.0	90,567.0	3.496	4.090	3,166,176.78	3,704,179.85	504,012.64
	TOTAL			**193,308.8**	**0.0**	**193,308.8**	**3.236**	**3.738**	**6,255,830.47**	**7,226,147.88**	**802,675.71**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ACTUAL FOR THE PERIOD: JANUARY 2013 THROUGH JUNE 2013

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL Jan-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	(125,469.76)
	VARIOUS	SCH. - D	22,297.0	0.0	0.0	22,297.0	4.355	4.355	970,960.89
	VARIOUS	OATT	953.0	0.0	0.0	953.0	2.549	2.549	24,292.97
	TOTAL		**23,250.0**	**0.0**	**0.0**	**23,250.0**	**3.741**	**3.741**	**869,784.10**
ACTUAL Feb-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	13,147.0	0.0	0.0	13,147.0	4.434	4.434	582,917.64
	VARIOUS	OATT	864.0	0.0	0.0	864.0	2.509	2.509	21,681.19
	TOTAL		**14,011.0**	**0.0**	**0.0**	**14,011.0**	**4.315**	**4.315**	**604,598.83**
ACTUAL Mar-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	2,411.0	0.0	0.0	2,411.0	3.377	3.377	81,413.67
	VARIOUS	OATT	487.0	0.0	0.0	487.0	2.430	2.430	11,834.03
	TOTAL		**2,898.0**	**0.0**	**0.0**	**2,898.0**	**3.218**	**3.218**	**93,247.70**
ACTUAL Apr-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	10,897.0	0.0	0.0	10,897.0	1.066	1.066	116,172.54
	VARIOUS	OATT	1,398.0	0.0	0.0	1,398.0	2.850	2.850	39,845.58
	TOTAL		**12,295.0**	**0.0**	**0.0**	**12,295.0**	**1.269**	**1.269**	**156,018.12**
ACTUAL May-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	12,814.0	0.0	0.0	12,814.0	1.052	1.052	134,802.69
	VARIOUS	OATT	1,383.0	0.0	0.0	1,383.0	2.688	2.688	37,174.69
	TOTAL		**14,197.0**	**0.0**	**0.0**	**14,197.0**	**1.211**	**1.211**	**171,977.38**
ACTUAL Jun-13									
	FPL	EMERG	150.0	0.0	0.0	150.0	16.637	16.637	24,955.50
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	27,743.34
	VARIOUS	SCH. - D	36,696.0	0.0	0.0	36,696.0	2.818	2.818	1,033,910.82
	VARIOUS	OATT	1,148.0	0.0	0.0	1,148.0	2.811	2.811	32,274.54
	TOTAL		**37,994.0**	**0.0**	**0.0**	**37,994.0**	**2.945**	**2.945**	**1,118,884.20**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ESTIMATED FOR THE PERIOD: JULY 2013 THROUGH DECEMBER 2013

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ESTIMATED Jul-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	32,010.0	0.0	0.0	32,010.0	5.174	5.174	1,656,270.0
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**32,010.0**	**0.0**	**0.0**	**32,010.0**	**5.174**	**5.174**	**1,656,270.00**
ESTIMATED Aug-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	23,570.0	0.0	0.0	23,570.0	4.808	4.808	1,133,340.0
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**23,570.0**	**0.0**	**0.0**	**23,570.0**	**4.808**	**4.808**	**1,133,340.00**
ESTIMATED Sep-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	30,710.0	0.0	0.0	30,710.0	5.343	5.343	1,640,920.0
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**30,710.0**	**0.0**	**0.0**	**30,710.0**	**5.343**	**5.343**	**1,640,920.00**
ESTIMATED Oct-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	17,070.0	0.0	0.0	17,070.0	4.972	4.972	848,780.0
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**17,070.0**	**0.0**	**0.0**	**17,070.0**	**4.972**	**4.972**	**848,780.00**
ESTIMATED Nov-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	12,360.0	0.0	0.0	12,360.0	4.884	4.884	603,610.0
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**12,360.0**	**0.0**	**0.0**	**12,360.0**	**4.884**	**4.884**	**603,610.00**
ESTIMATED Dec-13									
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	SCH. - D	4,300.0	0.0	0.0	4,300.0	4.547	4.547	195,540.0
	VARIOUS	OATT	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**4,300.0**	**0.0**	**0.0**	**4,300.0**	**4.547**	**4.547**	**195,540.00**
TOTAL Jan-13 THRU Dec-13	FPL	EMERG	150.0	0.0	0.0	150.0	16.637	16.637	24,955.50
	HPP	IPP	0.0	0.0	0.0	0.0	0.000	0.000	(97,726.42)
	VARIOUS	SCH. - D	218,282.0	0.0	0.0	218,282.0	4.122	4.122	8,998,638.25
	VARIOUS	OATT	6,233.0	0.0	0.0	6,233.0	2.681	2.681	167,103.00
	TOTAL		**224,665.0**	**0.0**	**0.0**	**224,665.0**	**4.047**	**4.047**	**9,092,970.33**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL	VARIOUS	CO-GEN.							
Jan-13		FIRM	5,664.0	0.0	0.0	5,664.0	2.598	2.598	147,141.11
		AS AVAIL.	24,643.0	0.0	0.0	24,643.0	2.857	2.857	704,143.00
	TOTAL		**30,307.0**	**0.0**	**0.0**	**30,307.0**	**2.809**	**2.809**	**851,284.11**
ACTUAL	VARIOUS	CO-GEN.							
Feb-13		FIRM	5,152.0	0.0	0.0	5,152.0	2.449	2.449	126,150.17
		AS AVAIL.	16,646.0	0.0	0.0	16,646.0	2.699	2.699	449,345.71
	TOTAL		**21,798.0**	**0.0**	**0.0**	**21,798.0**	**2.640**	**2.640**	**575,495.88**
ACTUAL	VARIOUS	CO-GEN.							
Mar-13		FIRM	5,670.0	0.0	0.0	5,670.0	2.612	2.612	148,122.67
		AS AVAIL.	15,148.0	0.0	0.0	15,148.0	2.750	2.750	416,575.04
	TOTAL		**20,818.0**	**0.0**	**0.0**	**20,818.0**	**2.713**	**2.713**	**564,697.71**
ACTUAL	VARIOUS	CO-GEN.							
Apr-13		FIRM	7,291.0	0.0	0.0	7,291.0	2.951	2.951	215,180.88
		AS AVAIL.	11,183.0	0.0	0.0	11,183.0	2.996	2.996	335,057.73
	TOTAL		**18,474.0**	**0.0**	**0.0**	**18,474.0**	**2.978**	**2.978**	**550,238.61**
ACTUAL	VARIOUS	CO-GEN.							
May-13		FIRM	7,636.0	0.0	0.0	7,636.0	2.852	2.852	217,769.52
		AS AVAIL.	10,449.0	0.0	0.0	10,449.0	2.964	2.964	309,664.06
	TOTAL		**18,085.0**	**0.0**	**0.0**	**18,085.0**	**2.916**	**2.916**	**527,433.58**
ACTUAL	VARIOUS	CO-GEN.							
Jun-13		FIRM	7,532.0	0.0	0.0	7,532.0	2.981	2.981	224,557.54
		AS AVAIL.	17,769.0	0.0	0.0	17,769.0	3.009	3.009	534,685.10
	TOTAL		**25,301.0**	**0.0**	**0.0**	**25,301.0**	**3.001**	**3.001**	**759,242.64**
ESTIMATED	VARIOUS	CO-GEN.							
Jul-13		FIRM	6,420.0	0.0	0.0	6,420.0	2.964	2.964	190,259.30
		AS AVAIL.	14,490.0	0.0	0.0	14,490.0	2.991	2.991	433,408.09
	TOTAL		**20,910.0**	**0.0**	**0.0**	**20,910.0**	**2.983**	**2.983**	**623,667.39**
ESTIMATED	VARIOUS	CO-GEN.							
Aug-13		FIRM	6,420.0	0.0	0.0	6,420.0	2.992	2.992	192,056.98
		AS AVAIL.	14,550.0	0.0	0.0	14,550.0	3.019	3.019	439,314.79
	TOTAL		**20,970.0**	**0.0**	**0.0**	**20,970.0**	**3.011**	**3.011**	**631,371.78**
ESTIMATED	VARIOUS	CO-GEN.							
Sep-13		FIRM	6,210.0	0.0	0.0	6,210.0	2.991	2.991	185,741.46
		AS AVAIL.	14,420.0	0.0	0.0	14,420.0	3.019	3.019	435,311.65
	TOTAL		**20,630.0**	**0.0**	**0.0**	**20,630.0**	**3.010**	**3.010**	**621,053.11**
ESTIMATED	VARIOUS	CO-GEN.							
Oct-13		FIRM	6,420.0	0.0	0.0	6,420.0	2.997	2.997	192,427.62
		AS AVAIL.	14,580.0	0.0	0.0	14,580.0	3.025	3.025	441,070.15
	TOTAL		**21,000.0**	**0.0**	**0.0**	**21,000.0**	**3.017**	**3.017**	**633,497.76**
ESTIMATED	VARIOUS	CO-GEN.							
Nov-13		FIRM	6,210.0	0.0	0.0	6,210.0	3.028	3.028	188,029.79
		AS AVAIL.	14,360.0	0.0	0.0	14,360.0	3.056	3.056	438,841.06
	TOTAL		**20,570.0**	**0.0**	**0.0**	**20,570.0**	**3.048**	**3.048**	**626,870.85**
ESTIMATED	VARIOUS	CO-GEN.							
Dec-13		FIRM	5,700.0	0.0	0.0	5,700.0	3.049	3.049	173,804.19
		AS AVAIL.	14,430.0	0.0	0.0	14,430.0	3.078	3.078	444,088.46
	TOTAL		**20,130.0**	**0.0**	**0.0**	**20,130.0**	**3.070**	**3.070**	**617,892.65**
TOTAL	VARIOUS	CO-GEN.							
Jan-13		FIRM	76,325.0	0.0	0.0	76,325.0	2.884	2.884	2,201,241.23
THRU		AS AVAIL.	182,668.0	0.0	0.0	182,668.0	2.946	2.946	5,381,504.84
Dec-13	TOTAL		**258,993.0**	**0.0**	**0.0**	**258,993.0**	**2.928**	**2.928**	**7,582,746.07**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
ACTUAL	VARIOUS	SCH. - REB	15.0	0.0	15.0	2.500	375.00	4.008	601.20	226.20
Jan-13	VARIOUS	SCH. - C	298.0	0.0	298.0	3.289	9,801.16	4.536	13,516.86	3,715.70
	VARIOUS	SCH. - J	52,366.0	0.0	52,366.0	3.150	1,649,366.00	3.662	1,917,498.78	268,132.78
	TOTAL		52,679.0	0.0	52,679.0	3.150	1,659,542.16	3.667	1,931,616.84	272,074.68
ACTUAL	VARIOUS	SCH. - REB	95.0	0.0	95.0	3.895	3,700.00	4.115	3,909.55	209.55
Feb-13	VARIOUS	SCH. - C	225.0	0.0	225.0	3.269	7,354.15	3.886	8,744.25	1,390.10
	VARIOUS	SCH. - J	45,225.0	0.0	45,225.0	2.916	1,318,821.50	3.254	1,471,829.31	153,007.81
	TOTAL		45,545.0	0.0	45,545.0	2.920	1,329,875.65	3.259	1,484,483.11	154,607.46
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
Mar-13	VARIOUS	SCH. - C	124.0	0.0	124.0	3.434	4,257.67	4.687	5,812.31	1,554.64
	VARIOUS	SCH. - J	14,030.0	0.0	14,030.0	3.434	481,726.00	4.153	582,728.98	101,002.98
	TOTAL		14,154.0	0.0	14,154.0	3.434	485,983.67	4.158	588,541.29	102,557.62
ACTUAL	VARIOUS	SCH. - REB	2,255.0	0.0	2,255.0	2.780	62,680.00	2.973	67,041.90	4,361.90
Apr-13	VARIOUS	SCH. - C	434.0	0.0	434.0	3.597	15,612.55	4.871	21,141.39	5,528.84
	VARIOUS	SCH. - J	140,055.0	0.0	140,055.0	3.533	4,947,811.50	3.876	5,427,968.15	480,156.65
	TOTAL		142,744.0	0.0	142,744.0	3.521	5,026,104.05	3.864	5,516,151.44	490,047.39
ACTUAL	VARIOUS	SCH. - REB	1,720.0	0.0	1,720.0	2.509	43,160.00	2.788	47,946.80	4,786.80
May-13	VARIOUS	SCH. - C	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
	VARIOUS	SCH. - J	77,027.0	0.0	77,027.0	3.592	2,767,004.00	3.740	2,880,765.12	113,761.12
	TOTAL		78,747.0	0.0	78,747.0	3.569	2,810,164.00	3.719	2,928,711.92	118,547.92
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
Jun-13	VARIOUS	SCH. - C	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
	VARIOUS	SCH. - J	24,262.0	0.0	24,262.0	3.814	925,277.00	4.203	1,019,640.84	94,363.84
	TOTAL		24,262.0	0.0	24,262.0	3.814	925,277.00	4.203	1,019,640.84	94,363.84
ESTIMATED	VARIOUS	ECONOMY	18,580.0	0.0	18,580.0	4.024	747,689.95	4.379	813,628.55	65,938.60
Jul-13	TOTAL		18,580.0	0.0	18,580.0	4.024	747,689.95	4.379	813,628.55	65,938.60
ESTIMATED	VARIOUS	ECONOMY	8,330.0	0.0	8,330.0	4.133	344,302.22	4.952	412,469.20	68,166.98
Aug-13	TOTAL		8,330.0	0.0	8,330.0	4.133	344,302.22	4.952	412,469.20	68,166.98
ESTIMATED	VARIOUS	ECONOMY	18,490.0	0.0	18,490.0	4.245	784,968.71	4.600	850,452.75	65,484.03
Sep-13	TOTAL		18,490.0	0.0	18,490.0	4.245	784,968.71	4.600	850,452.75	65,484.03
ESTIMATED	VARIOUS	ECONOMY	12,530.0	0.0	12,530.0	4.439	556,234.54	5.203	651,988.05	95,753.51
Oct-13	TOTAL		12,530.0	0.0	12,530.0	4.439	556,234.54	5.203	651,988.05	95,753.51
ESTIMATED	VARIOUS	ECONOMY	10,110.0	0.0	10,110.0	4.361	440,858.43	5.193	525,001.07	84,142.64
Nov-13	TOTAL		10,110.0	0.0	10,110.0	4.361	440,858.43	5.193	525,001.07	84,142.64
ESTIMATED	VARIOUS	ECONOMY	14,530.0	0.0	14,530.0	4.219	613,033.97	4.975	722,800.51	109,766.54
Dec-13	TOTAL		14,530.0	0.0	14,530.0	4.219	613,033.97	4.975	722,800.51	109,766.54
TOTAL	VARIOUS	SCH. - REB	4,085.0	0.0	4,085.0	2.691	109,915.00	2.925	119,499.45	9,584.45
Jan-13	VARIOUS	SCH. - C	1,081.0	0.0	1,081.0	3.425	37,025.53	4.553	49,214.81	12,189.28
THRU	VARIOUS	SCH. - J	352,965.0	0.0	352,965.0	3.425	12,090,006.00	3.768	13,300,431.18	1,210,425.18
Dec-13	VARIOUS	ECONOMY	82,570.0	0.0	82,570.0	4.223	3,487,087.82	4.816	3,976,340.13	489,252.31
	TOTAL		440,701.0	0.0	440,701.0	3.568	15,724,034.35	3.959	17,445,485.57	1,721,451.22

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

CAPACITY COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2013 THROUGH DECEMBER 2013

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2013 THROUGH DECEMBER 2013

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2012 THROUGH DECEMBER 2012	($126,648)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2013 THROUGH DECEMBER 2013	(465,117)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2014 THROUGH DECEMBER 2014	($591,765)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2013 THROUGH DECEMBER 2013

	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Estimated Jul-13	Estimated Aug-13	Estimated Sep-13	Estimated Oct-13	Estimated Nov-13	Estimated Dec-13	Total
1 UNIT POWER CAPACITY CHARGES	1,411,229	1,408,204	1,408,398	1,434,065	2,053,921	1,579,068	1,497,890	1,497,890	1,497,890	1,497,890	1,497,890	1,497,890	18,282,225
2 CAPACITY PAYMENTS TO COGENERATORS	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	13,383,240
3 (UNIT POWER CAPACITY REVENUES)	(13,105)	(34,868)	(141,219)	(241,263)	(206,895)	(121,888)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,538)	(1,518,476)
4 TOTAL CAPACITY DOLLARS	2,513,394	2,488,606	2,382,449	2,308,072	2,962,296	2,572,450	2,486,620	2,486,620	2,486,620	2,486,620	2,486,620	2,486,622	30,146,989
5 SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6 JURISDICTIONAL CAPACITY DOLLARS	2,513,394	2,488,606	2,382,449	2,308,072	2,962,296	2,572,450	2,486,620	2,486,620	2,486,620	2,486,620	2,486,620	2,486,622	30,146,989
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	2,777,423	2,561,761	2,632,627	2,766,435	2,917,104	3,336,068	3,548,491	3,536,784	3,586,389	3,241,850	2,776,091	2,707,636	36,388,659
8 PRIOR PERIOD TRUE-UP PROVISION	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,542)	(558,543)	(6,702,505)
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	2,218,881	2,003,219	2,074,085	2,207,893	2,358,562	2,777,526	2,989,949	2,978,242	3,027,847	2,683,308	2,217,549	2,149,093	29,686,154
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	(294,513)	(485,387)	(308,364)	(100,179)	(603,734)	205,076	503,329	491,622	541,227	196,688	(269,071)	(337,529)	(460,835)
11 INTEREST PROVISION FOR MONTH	(402)	(522)	(509)	(421)	(348)	(272)	(454)	(522)	(361)	(222)	(144)	(105)	(4,282)
12 ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
13 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(6,829,153)	(6,565,526)	(6,492,893)	(6,243,224)	(5,785,282)	(5,830,822)	(5,067,476)	(4,006,059)	(2,956,417)	(1,857,009)	(1,102,001)	(812,674)	(6,829,153)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,542	558,543	6,702,505
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	**(6,565,526)**	**(6,492,893)**	**(6,243,224)**	**(5,785,282)**	**(5,830,822)**	**(5,067,476)**	**(4,006,059)**	**(2,956,417)**	**(1,857,009)**	**(1,102,001)**	**(812,674)**	**(591,765)**	**(591,765)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2013 THROUGH DECEMBER 2013

	Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Estimated Jul-13	Estimated Aug-13	Estimated Sep-13	Estimated Oct-13	Estimated Nov-13	Estimated Dec-13	Total
1 BEGINNING TRUE-UP AMOUNT	(6,829,153)	(6,565,526)	(6,492,893)	(6,243,224)	(5,785,282)	(5,830,822)	(5,067,476)	(4,006,059)	(2,956,417)	(1,857,009)	(1,102,001)	(812,674)	(6,829,153)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(6,565,124)	(6,492,371)	(6,242,715)	(5,784,861)	(5,830,474)	(5,067,204)	(4,005,605)	(2,955,895)	(1,856,648)	(1,101,779)	(812,530)	(591,660)	(587,483)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(13,394,277)	(13,057,897)	(12,735,608)	(12,028,085)	(11,615,756)	(10,898,026)	(9,073,081)	(6,961,954)	(4,813,065)	(2,958,788)	(1,914,531)	(1,404,334)	(7,416,636)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(6,697,139)	(6,528,949)	(6,367,804)	(6,014,043)	(5,807,878)	(5,449,013)	(4,536,541)	(3,480,977)	(2,406,533)	(1,479,394)	(957,266)	(702,167)	(3,708,318)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.050	0.090	0.100	0.080	0.080	0.070	0.060	0.180	0.180	0.180	0.180	0.180	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.090	0.100	0.080	0.080	0.070	0.060	0.180	0.180	0.180	0.180	0.180	0.180	NA
7 TOTAL (LINE 5 + LINE 6)	0.140	0.190	0.180	0.160	0.150	0.130	0.240	0.360	0.360	0.360	0.360	0.360	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.070	0.095	0.090	0.080	0.075	0.065	0.120	0.180	0.180	0.180	0.180	0.180	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.006	0.008	0.008	0.007	0.006	0.005	0.010	0.015	0.015	0.015	0.015	0.015	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(402)	(522)	(509)	(421)	(348)	(272)	(454)	(522)	(361)	(222)	(144)	(105)	(4,282)

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
ORANGE COGEN LP	4/17/1989	12/31/2015	QF	QF = QUALIFYING FACILITY
CALPINE	11/1/2011	12/31/2016	LT	LT = LONG TERM
PASCO COGEN LTD	1/1/2009	12/31/2018	LT	ST = SHORT-TERM
OLEANDER	1/1/2013	12/31/2015	LT	** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
SEMINOLE ELECTRIC **	6/1/1992	12/31/2016		

CONTRACT	ACT JANUARY MW	ACT FEBRUARY MW	ACT MARCH MW	ACT APRIL MW	ACT MAY MW	ACT JUNE MW	EST JULY MW	EST AUGUST MW	EST SEPTEMBER MW	EST OCTOBER MW	EST NOVEMBER MW	EST DECEMBER MW
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
PASCO COGEN LTD	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
OLEANDER	160.0	160.0	160.0	160.0	160.0	160.0	155.0	155.0	155.0	155.0	155.0	155.0
SEMINOLE ELECTRIC	1.1	1.1	4.8	5.3	1.0	1.2	1.5	1.7	1.4	1.4	1.2	1.2

CAPACITY	ACT JANUARY ($)	ACT FEBRUARY ($)	ACT MARCH ($)	ACT APRIL ($)	ACT MAY ($)	ACT JUNE ($)	EST JULY ($)	EST AUGUST ($)	EST SEPTEMBER ($)	EST OCTOBER ($)	EST NOVEMBER ($)	EST DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	1,115,270	13,383,240
TOTAL COGENERATION	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 1,115,270	$ 13,383,240

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 2, Page 4 of 5

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2013 THROUGH DECEMBER 2013

SCHEDULE E12

CAPACITY	ACT JANUARY ($)	ACT FEBRUARY ($)	ACT MARCH ($)	ACT APRIL ($)	ACT MAY ($)	ACT JUNE ($)	EST JULY ($)	EST AUGUST ($)	EST SEPTEMBER ($)	EST OCTOBER ($)	EST NOVEMBER ($)	EST DECEMBER ($)	TOTAL ($)
HARDEE POWER PARTNERS													
CALPINE - D													
OLEANDER - D													
PASCO COGEN LTD - D													
FLORIDA POWER & LIGHT-EMERG A													
ORLANDO UTILITIES													
FLORIDA POWER & LIGHT													
PROGRESS ENERGY FLORIDA													
THE ENERGY AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
PROGRESS ENERGY FLORIDA - CB													
FLORIDA POWER & LIGHT - CB													
ORLANDO UTILITIES - CB													
REEDY CREEK - CB													
SEMINOLE ELECTRIC - CB													
THE ENERGY AUTHORITY - CB													
VARIOUS - MA													
CITY OF LAKELAND - MA													
EXGEN (CONSTELLATION) - MA													
THE ENERGY AUTHORITY - MA													
J P MORGAN VENTURES - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
CITY OF HOMESTEAD - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	$ 1,398,124	$ 1,373,336	$ 1,267,179	$ 1,192,802	$ 1,847,026	$ 1,457,180	$ 1,371,350	$ 1,371,350	$ 1,371,350	$ 1,371,350	$ 1,371,350	$ 1,371,352	$ 16,763,749
TOTAL CAPACITY	$ 2,513,394	$ 2,488,606	$ 2,382,449	$ 2,308,072	$ 2,962,296	$ 2,572,450	$ 2,486,620	$ 2,486,620	$ 2,486,620	$ 2,486,620	$ 2,486,620	$ 2,486,622	$ 30,146,989

Docket No. 130001-EI
Exhibit No. ____ (PAR-2)
Document No. 2, Page 5 of 5

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

POLK UNIT 1 IGNITION OIL CONVERSION

ACTUAL/ESTIMATED

JANUARY 2013 - DECEMBER 2013

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY, 2013 THROUGH JUNE, 2013

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	TOTAL
1	BEGINNING BALANCE						$ -	$ -
2	ADD INVESTMENT						15,428,062	15,428,062
3	LESS RETIREMENTS						-	-
4	ENDING BALANCE						15,428,062	15,428,062
5								
6								
7	AVERAGE BALANCE						-	
8	DEPRECIATION RATE						1.666667%	
9	DEPRECIATION EXPENSE						-	-
10	LESS RETIREMENTS						-	-
11	BEGINNING BALANCE DEPRECIATION						-	-
12	ENDING BALANCE DEPRECIATION						-	-
13								
14								
15	ENDING NET INVESTMENT						15,428,062	$ 15,428,062
16								
17								
18	AVERAGE INVESTMENT						$ 7,714,031	
19	ALLOWED EQUITY RETURN						.44625%	
20	EQUITY COMPONENT AFTER-TAX						34,424	34,424
21	CONVERSION TO PRE-TAX						1.62800	
22	EQUITY COMPONENT PRE-TAX						56,042	56,042
23								
24	ALLOWED DEBT RETURN						.24437%	
25	DEBT COMPONENT						18,851	18,851
26								
27	TOTAL RETURN REQUIREMENTS						74,893	74,893
28								
29	TOTAL DEPRECIATION & RETURN						74,893	$ 74,893
30								
31	ESTIMATED FUEL SAVINGS						5,993,236	$ 5,993,236
32	TOTAL DEPRECIATION & RETURN						74,893	$ 74,893
33	NET BENEFIT (COST) TO RATEPAYER						5,918,343	$ 5,918,343
34								

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 10.63% (EQUITY 7.8693% , DEBT 2.7582%).
THE RATES ARE FROM THE MAY 2012 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%

Computation of Savings	MARCH	APRIL	MAY	JUNE	Total
A4,clmn m,#2 oil				$0.33320	
A4,clmn m,NG				$0.03526	
#2 Oil less NG				$0.29794	
Gen. Cost Anal. Rept - Generation kWh				19,508,000	
Oil conversion Savings (@ PK 1 CT)				**$5,812,168**	
Cost of propane $/mmbtu				$12.95	
Cost of NG $/mmbtu (A4 Polk)				$4.85	
NG mmbtu's propane equivalent burned				7,324	
Propane conversion savings				**$59,301**	
Cost of oil $/mmbtu				$25.56	
Cost of NG $/mmbtu (A4 Polk)				$4.85	
NG mmbtu's oil equivalent burned				5,881	
Oil conversion savings (Auxiliary Fuel)				**$121,767**	
Total Fuel Savings				**$5,993,236**	**$5,993,236**

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JULY, 2013 THROUGH DECEMBER, 2013

		JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062
2	ADD INVESTMENT	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-
4	ENDING BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062
5								
6								
7	AVERAGE BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	257,134	257,134	257,134	257,134	257,134	257,134	1,542,806
10	LESS RETIREMENTS	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	-	257,134	514,269	771,403	1,028,537	1,285,672	-
12	ENDING BALANCE DEPRECIATION	257,134	514,269	771,403	1,028,537	1,285,672	1,542,806	1,542,806
13								
14								
15	ENDING NET INVESTMENT	15,170,927	14,913,793	14,656,659	14,399,524	14,142,390	13,885,256	13,885,256
16								
17								
18	AVERAGE INVESTMENT	$ 15,299,494	$ 15,042,360	$ 14,785,226	$ 14,528,091	$ 14,270,957	$ 14,013,823	
19	ALLOWED EQUITY RETURN	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	
20	EQUITY COMPONENT AFTER-TAX	61,477	60,444	59,411	58,378	57,344	56,311	353,365
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	100,085	98,403	96,721	95,039	93,356	91,674	575,278
23								
24	ALLOWED DEBT RETURN	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	
25	DEBT COMPONENT	28,407	27,930	27,452	26,975	26,498	26,020	163,282
26								
27	TOTAL RETURN REQUIREMENTS	128,492	126,333	124,173	122,014	119,854	117,694	738,560
28								
29	TOTAL DEPRECIATION & RETURN	385,626	383,467	381,307	379,148	376,988	374,828	2,281,366
31	ESTIMATED FUEL SAVINGS	$968,507	$966,604	$869,203	$1,594,632	$652,549	$865,196	$5,916,691
32	TOTAL DEPRECIATION & RETURN	$385,626	$383,467	$381,307	$379,148	$376,988	$374,828	$2,281,366
33	NET BENEFIT (COST) TO RATEPAYER	$582,881	$583,137	$487,895	$1,215,484	$275,560	$490,367	$3,635,325
34								

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 10.08% (EQUITY 7.8501% , DEBT 2.2281%).
THE RATES ARE FROM THE MAY 2013 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%

Computation of Savings	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	Total
A4,clmn m,#2 oil	$0.33320	$0.33320	$0.33320	$0.33320	$0.33320	$0.33320	
A4,clmn m,NG	$0.04750	$0.04890	$0.05190	$0.05490	$0.06130	$0.05410	
#2 Oil less NG	$0.28570	$0.28430	$0.28130	$0.27830	$0.27190	$0.27910	
Gen. Cost Anal. Rept - Generation kWh	3,390,000	3,400,000	3,090,000	5,730,000	2,400,000	3,100,000	
Oil conversion Savings (@ CT)	**$968,507**	**$966,604**	**$869,203**	**$1,594,632**	**$652,549**	**$865,196**	
Cost of propane $/mmbtu	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Cost of NG $/mmbtu (A4 Polk)	$6.35	$0.00	$0.00	$0.00	$0.00	$0.00	
NG mmbtu's propane equivalent burned	-	-	-	-	-	-	
Propane conversion savings	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	
Cost of oil $/mmbtu	$22.07	$0.00	$0.00	$0.00	$0.00	$0.00	
Cost of NG $/mmbtu (A4 Polk)	$6.35	$0.00	$0.00	$0.00	$0.00	$0.00	
NG mmbtu's oil equivalent burned	-	-	-	-	-	-	
Oil conversion savings (Aux Boiler)	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	
Total Fuel Savings	**$968,507**	**$966,604**	**$869,203**	**$1,594,632**	**$652,549**	**$865,196**	**$5,916,691**

DOCKET NO. 130001-EI
CCR 2013 PROJECTION FILING
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2014 - DECEMBER 2014

AND

SCHEDULE E12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 48
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Penelope A. Rusk - PAR-3 (Composite)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED
REVISED 9/16/13

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 1/13 AVG DEMAND FACTOR (%)
RS,RSVP	54.87%	8,568,132	1,783	1.07880	1.05641	9,051,474	1,923	46.84%	55.51%	54.85%
GS, TS	59.77%	1,014,542	194	1.07880	1.05640	1,071,759	209	5.55%	6.03%	5.99%
GSD Optional	3.29%	332,164	50	1.07454	1.05252	349,609	54	1.81%	1.56%	1.58%
GSD, SBF	72.26%	7,305,930	1,104	1.07454	1.05252	7,689,640	1,186	39.80%	34.24%	34.67%
IS,SBI	121.20%	912,924	86	1.03010	1.01750	928,901	89	4.81%	2.57%	2.74%
LS1	793.34%	218,515	3	1.07880	1.05641	230,842	3	1.19%	0.09%	0.17%
TOTAL		18,352,207	3,220			19,322,225	3,464	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2013 projected calendar data.
(2) Projected MWH sales for the period January 2014 thru December 2014.
(3) Based on 12 months average CP at meter.
(4) Based on 2013 projected demand losses.
(5) Based on 2013 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 0.0769 + Col (9) * 0.9231

Docket No. 130001-EI
Exhibit No. _____ (PAR-3)
Document No. 1, Page 1 of 4
REVISED: 9/16/2013

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	18,163,440
2	CAPACITY PAYMENTS TO COGENERATORS	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
3	(UNIT POWER CAPACITY REVENUES)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,536)	(1,518,476)
4	TOTAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2013 - DEC. 2013													591,765
8	TOTAL													$31,472,809
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$31,495,469

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED
REVISED 9/16/13

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	46.84%	55.51%	1,134,466	16,138,682	17,273,148	8,568,132	8,568,132				0.00202
GS, TS	5.55%	6.03%	134,421	1,753,130	1,887,551	1,014,542	1,014,542				0.00186
GSD, SBF											
Secondary						6,051,001	6,051,001			0.63	
Primary						1,250,425	1,237,921			0.62	
Transmission						4,504	4,414			0.62	
GSD, SBF - Standard	39.80%	34.24%	963,957	9,954,755	10,918,712	7,305,930	7,293,336	57.91%	17,253,768		
GSD - Optional	1.81%	1.56%	43,838	453,546	497,384						
Secondary						321,510	321,510				0.00150
Primary						10,654	10,547				0.00149
IS, SBI											
Primary						228,187	225,905			0.39	
Transmission						684,737	671,042			0.38	
Total IS, SBI	4.81%	2.57%	116,498	747,188	863,686	912,924	896,947	56.10%	2,190,267		
LS1	1.19%	0.09%	28,822	26,166	54,988	218,515	218,515				0.00025
TOTAL	100.00%	100.00%	2,422,002	29,073,467	31,495,469	18,352,207	18,323,529				0.00172

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * 0.0769 * Col (1).
(4) Total capacity costs * 0.9231 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2014 through December 2014.
(7) Projected kWh sales at secondary for the period January 2014 through December 2014.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2014 through December 2014.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
Document No. 1, Page 3 of 4
REVISED: 9/16/2013

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
ORANGE COGEN LP	4/17/1989	12/31/2015	QF	QF = QUALIFYING FACILITY
CALPINE	11/1/2011	12/31/2016	LT	LT = LONG TERM
PASCO COGEN	1/1/2009	12/31/2018	LT	ST = SHORT-TERM
OLEANDER	1/1/2013	12/31/2015	LT	** THREE YEAR NOTICE REQUIRED FOR TERMINATION.
SEMINOLE ELECTRIC **	6/1/1992	12/31/2016		

CONTRACT	JANUARY MW	FEBRUARY MW	MARCH MW	APRIL MW	MAY MW	JUNE MW	JULY MW	AUGUST MW	SEPTEMBER MW	OCTOBER MW	NOVEMBER MW	DECEMBER MW
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
PASCO COGEN	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
OLEANDER	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
SEMINOLE ELECTRIC	1.4	1.4	1.5	1.8	1.3	1.4	1.5	1.7	1.4	1.4	1.2	1.2

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
TOTAL COGENERATION	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
CALPINE - D	[redacted]												
PASCO COGEN - D													
OLEANDER - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,080	1,387,084	16,644,964
TOTAL CAPACITY	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,420**	**$2,573,424**	**$30,881,044**

Docket No. 130001-EI
Exhibit No.____ (PAR-3)
Document No. 1, Page 4 of 4

DOCKET NO. 130001-EI
CCR 2014 PROJECTION FILING
EXHIBIT NO.____ (PAR-3)
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED CAPACITY COST RECOVERY

JANUARY 2014 - DECEMBER 2014

CALCULATIONS UTILIZING PROPOSED RATE DESIGN

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER (%)	(2) PROJECTED SALES AT METER (MWH)	(3) PROJECTED AVG 12 CP AT METER (MW)	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION (MWH)	(7) PROJECTED AVG 12 CP AT GENERATION (MW)	(8) PERCENTAGE OF SALES AT GENERATION (%)	(9) PERCENTAGE OF DEMAND AT GENERATION (%)	(10) 12 CP & 50% AVG DEMAND FACTOR (%)
RS,RSVP	54.87%	8,568,132	1,783	1.07880	1.05641	9,051,474	1,923	46.85%	55.52%	51.18%
GS, TS	59.77%	1,014,542	194	1.07880	1.05640	1,071,759	209	5.55%	6.03%	5.79%
GSD Optional	3.06%	332,164	48	1.07146	1.04897	348,430	52	1.80%	1.50%	1.65%
GSD, SBF, IS, SBI	75.65%	8,218,854	1,192	1.07146	1.04897	8,621,318	1,277	44.61%	36.86%	40.74%
LS1	793.34%	218,515	3	1.07880	1.05641	230,842	3	1.19%	0.09%	0.64%
TOTAL		18,352,207	3,220			19,323,823	3,464	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2013 projected calendar data.
(2) Projected MWH sales for the period January 2014 thru December 2014.
(3) Based on 12 months average CP at meter.
(4) Based on 2013 projected demand losses.
(5) Based on 2013 projected energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Based on 12 months average percentage of sales at generation.
(9) Based on 12 months average percentage of demand at generation.
(10) Col (8) * 50% + Col (9) * 50%

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	1,513,620	18,163,440
2	CAPACITY PAYMENTS TO COGENERATORS	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	1,186,340	14,236,080
3	(UNIT POWER CAPACITY REVENUES)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,540)	(126,536)	(1,518,476)
4	TOTAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
5	SEPARATION FACTOR	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6	JURISDICTIONAL CAPACITY DOLLARS	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,420	$2,573,424	$30,881,044
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2013 - DEC. 2013													591,765
8	TOTAL													$31,472,809
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$31,495,469

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2014 THROUGH DECEMBER 2014
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION (%)	(2) PERCENTAGE OF DEMAND AT GENERATION (%)	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER (MWH)	(7) EFFECTIVE AT SECONDARY LEVEL (MWH)	(8) BILLING KW LOAD FACTOR (%)	(9) PROJECTED BILLED KW AT METER (kw)	(10) CAPACITY RECOVERY FACTOR ($/kw)	(11) CAPACITY RECOVERY FACTOR ($/kwh)
RS	46.85%	55.52%	7,377,814	8,743,143	16,120,957	8,568,132	8,568,132				0.00188
GS, TS	5.55%	6.03%	873,999	949,588	1,823,587	1,014,542	1,014,542				0.00180
GSD, SBF, IS, SBI											
Secondary						6,051,001	6,051,001			0.66	
Primary						1,478,612	1,463,826			0.65	
Transmission						689,241	675,456			0.65	
GSD,SBF,IS,SBI-Standard	44.61%	36.86%	7,025,065	5,804,615	12,829,680	8,218,854	8,190,283	57.70%	19,444,035		
GSD - Optional	1.80%	1.50%	283,459	236,216	519,675						
Secondary						321,510	321,510				0.00157
Primary						10,654	10,547				0.00155
LS1	1.19%	0.09%	187,398	14,173	201,571	218,515	218,515				0.00092
TOTAL	100.00%	100.00%	15,747,735	15,747,735	31,495,470	18,352,207	18,323,529				0.00172

(1) Obtained from page 1.
(2) Obtained from page 1.
(3) Total capacity costs * .50 * Col (1).
(4) Total capacity costs * .50 * Col (2).
(5) Col (3) + Col (4).
(6) Projected kWh sales for the period January 2014 through December 2014.
(7) Projected kWh sales at secondary for the period January 2014 through December 2014.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2014 through December 2014.
(10) Total Col (5) / Total Col (9).
(11) {Col (5) / Total Col (7)} / 1000.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2014 - DECEMBER 2014

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2014 - DEC. 2014)
3	Schedule E1-A Calculation of Total True-Up	(")
4	Schedule E1-C GPIF & True-Up Adj. Factors	(")
5	Schedule E1-D Fuel Adjustment Factor for TOD	(")
6	Schedule E1-E Fuel Recovery Factor-with Line Losses	(")
7	Schedule E2 Cost Recovery Clause Calculation (By Month)	(")
8-9	Schedule E3 Generating System Comparative Data	(")
10-21	Schedule E4 System Net Generation & Fuel Cost	(")
22-23	Schedule E5 Inventory Analysis	(")
24-25	Schedule E6 Power Sold	(")
26-27	Schedule E7 Purchased Power	(")
28	Schedule E8 Energy Payment to Qualifying Facilities	(")
29	Schedule E9 Economy Energy Purchases	(")
30	Schedule E10 Residential Bill Comparison	(")
31	Schedule H1 Generating System Comparative Data	(JAN. - DEC. 2011-2014)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1
REVISED 9/16/13

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	697,757,539	18,522,902	3.76700
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Polk 1 Conversion Depreciation & ROI	4,250,042	18,522,902 (1)	0.02294
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4a)**	**702,007,581**	**18,522,902**	**3.78994**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	7,983,730	182,710	4.36962
7.	Energy Cost of Economy Purchases (E9)	20,352,480	495,850	4.10456
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	8,348,560	266,600	3.13149
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**36,684,770**	**945,160**	**3.88133**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		19,468,062	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	327,980	10,320	3.17810
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	5,053,522	150,010	3.36879
14.	Gains on Sales	522,912	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**5,904,414**	**160,330**	**3.68266**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		2,739	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**732,787,937**	**19,304,993**	**3.79585**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,261,741 (1)	33,240	0.00688
22.	T & D Losses	34,904,580 (1)	919,546	0.19019
23.	System MWH Sales	732,787,937	18,352,207	3.99291
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	732,787,937	18,352,207	3.99291
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	732,787,937	18,352,207	3.99291
28.	True-up (2)	(15,630,547)	18,352,207	(0.08517)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	717,157,390	18,352,207	3.90774
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	717,673,743	18,352,207	3.91055
32.	GPIF Adjusted for Taxes (2)	(1,177,059)	18,352,207	(0.00641)
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	716,496,684	18,352,207	3.90414
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.904**

(a) Data not available at this time.
(1) Included For Informational Purposes Only
(2) Calculation Based on Jurisdictional MWH Sales

TAMPA ELECTRIC COMPANY
CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2013 - December 2013 (6 months actual, 6 months estimated)	$14,727,476
2.	FINAL TRUE-UP (January 2012 - December 2012) (Per True-Up filed March 1, 2013)	903,071
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2014 through December 2014 (Schedule E1, line 28)	$15,630,547
4.	JURISDICTIONAL MWH SALES (Projected January 2014 through December 2014)	18,352,207
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.0852)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2014 through December 2014)	($1,177,059)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2013 through December 2013)	$15,630,547	
2.	TOTAL SALES (January 2014 through December 2014)	18,352,207	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0064)**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.0852)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E1-D
REVISED 9/16/13

		NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK		29.77	$30.45
OFF PEAK		70.23	$28.20
		100.00	1.0798

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$732,787,937		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	18,352,207		
2a	Effective MWH Sales (Jurisd)		18,323,529		
3	Cost Per KWH Sold	(line 1 / line 2)	3.9929		
4	Jurisdictional Loss Factor		1.00000		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($15,630,547)		
7	TOTAL	(line 1 x line 4)+line 6	$717,157,390		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.9167		
10	GPIF Factor	(Sch E1-C line 3a)	-0.0064		
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.9103	4.1244	3.8196
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.910	4.124	3.820

13	Hours: ON PEAK	24.91%
14	OFF PEAK	75.09%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,173,700	16,173,700
Distribution Primary	1,489,266	1,474,373
Transmission	689,241	675,456
Total	18,352,207	18,323,529

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.910	4.124	3.820
Distribution Primary	3.871	4.083	3.782
Transmission	3.832	4.042	3.744
RS 1st Tier	3.609		
RS 2nd Tier	4.609		
Lighting	3.872		

SCHEDULE E1-E
REVISED 9/16/13

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		3.609	4.609
Distribution Secondary	3.910		
Distribution Primary	3.871		
Transmission	3.832		
Lighting Service (1)	3.872		
TIME-OF-USE			
Distribution Secondary - On-Peak	4.124		
Distribution Secondary - Off-Peak	3.820		
Distribution Primary - On-Peak	4.083		
Distribution Primary - Off-Peak	3.782		
Transmission - On-Peak	4.042		
Transmission - Off-Peak	3.744		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E2
REVISED 9/16/13

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
							ESTIMATED							TOTAL
		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	PERIOD
1.	Fuel Cost of System Net Generation	54,026,073	46,518,588	50,183,232	51,302,298	61,032,207	66,536,436	69,894,111	69,152,707	65,462,249	60,042,905	50,544,871	53,061,862	697,757,539
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	652,887	554,727	677,617	677,247	397,987	429,767	371,467	389,687	390,397	419,717	376,377	566,537	5,904,414
4.	Fuel Cost of Purchased Power	89,300	145,200	318,620	445,600	693,330	737,440	1,108,000	1,628,410	1,425,970	653,690	669,860	68,310	7,983,730
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	719,520	588,340	805,950	672,500	731,650	704,150	744,650	766,740	679,460	720,410	719,170	496,020	8,348,560
7.	Energy Cost of Economy Purchases	1,118,480	1,107,530	1,496,400	1,405,270	1,843,860	1,865,250	2,517,540	1,967,230	2,439,700	1,942,060	1,308,440	1,340,720	20,352,480
8.	Polk 1 Conversion Depreciation & ROI	365,289	363,268	361,246	359,224	357,201	355,181	353,160	351,138	349,116	347,094	345,073	343,052	4,250,042
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**55,665,775**	**48,168,199**	**52,487,831**	**53,507,645**	**64,260,261**	**69,768,690**	**74,245,994**	**73,476,538**	**69,966,098**	**63,286,442**	**53,211,037**	**54,743,427**	**732,787,937**
10.	Jurisdictional MWH Sold	1,441,299	1,307,512	1,275,034	1,313,445	1,476,467	1,741,216	1,808,913	1,766,966	1,827,507	1,635,979	1,398,110	1,359,759	18,352,207
11.	Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	55,665,775	48,168,199	52,487,831	53,507,645	64,260,261	69,768,690	74,245,994	73,476,538	69,966,098	63,286,442	53,211,037	54,743,427	732,787,937
13.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
14.	**JURISD. TOTAL FUEL & NET PWR. TRANS.** Adjusted for Line Losses (Line 12 * Line 13)	**55,665,775**	**48,168,199**	**52,487,831**	**53,507,645**	**64,260,261**	**69,768,690**	**74,245,994**	**73,476,538**	**69,966,098**	**63,286,442**	**53,211,037**	**54,743,427**	**732,787,937**
15.	Cost Per kWh Sold (Cents/kWh)	3.8622	3.6840	4.1166	4.0738	4.3523	4.0069	4.1045	4.1583	3.8285	3.8684	3.8059	4.0260	3.9929
16.	True-up (Cents/kWh) [2]	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)	(0.0852)
17.	Total (Cents/kWh) (Line 15+16)	3.7770	3.5988	4.0314	3.9886	4.2671	3.9217	4.0193	4.0731	3.7433	3.7832	3.7207	3.9408	3.9077
18.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
19.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.7797	3.6014	4.0343	3.9915	4.2702	3.9245	4.0222	4.0760	3.7460	3.7859	3.7234	3.9436	3.9105
20.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)	(0.0064)
21.	**TOTAL RECOVERY FACTOR (LINE 19+20)**	**3.7733**	**3.5950**	**4.0279**	**3.9851**	**4.2638**	**3.9181**	**4.0158**	**4.0696**	**3.7396**	**3.7795**	**3.7170**	**3.9372**	**3.9041**
22.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.773**	**3.595**	**4.028**	**3.985**	**4.264**	**3.918**	**4.016**	**4.070**	**3.740**	**3.780**	**3.717**	**3.937**	**3.904**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
Document No. 3, Page 7 of 31
REVISED: 9/16/2013

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E3

	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	80,865	107,291	102,000	49,256	49,743	105,938
3. COAL	38,040,790	27,394,532	31,207,087	28,242,538	31,661,806	36,835,660
4. NATURAL GAS	15,904,418	19,016,765	18,874,145	23,010,504	29,320,658	29,594,838
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**54,026,073**	**46,518,588**	**50,183,232**	**51,302,298**	**61,032,207**	**66,536,436**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	337	446	424	191	203	419
10. COAL	1,101,920	791,140	911,930	827,440	930,410	1,092,280
11. NATURAL GAS	339,142	469,457	446,736	537,049	704,587	701,571
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,441,399**	**1,261,043**	**1,359,090**	**1,364,680**	**1,635,200**	**1,794,270**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	3,360	5,340	4,410	3,020	3,120	2,630
17. COAL (TON)	469,920	335,860	390,690	352,470	396,480	466,490
18. NATURAL GAS (MCF)	2,427,330	3,319,240	3,238,340	3,926,100	5,192,270	5,256,930
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	0	0	0	0	0	0
22. LIGHT OIL	3,620	4,800	4,560	2,050	2,190	4,510
23. COAL	11,249,400	8,085,790	9,292,300	8,489,470	9,528,280	11,161,760
24. NATURAL GAS	2,490,780	3,408,790	3,319,970	4,031,560	5,322,830	5,395,630
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**13,743,800**	**11,499,380**	**12,616,830**	**12,523,080**	**14,853,300**	**16,561,900**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.04	0.03	0.01	0.01	0.02
30. COAL	76.45	62.73	67.10	60.64	56.90	60.88
31. NATURAL GAS	23.53	37.23	32.87	39.35	43.09	39.10
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
36. LIGHT OIL ($/BBL)	24.07	20.09	23.13	16.31	15.94	40.28
37. COAL ($/TON)	80.95	81.57	79.88	80.13	79.86	78.96
38. NATURAL GAS ($/MCF)	6.55	5.73	5.83	5.86	5.65	5.63
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	22.34	22.35	22.37	24.03	22.71	23.49
43. COAL	3.38	3.39	3.36	3.33	3.32	3.30
44. NATURAL GAS	6.39	5.58	5.69	5.71	5.51	5.48
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.93**	**4.05**	**3.96**	**4.10**	**4.11**	**4.02**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	10,747	10,751	10,747	10,741	10,768	10,755
50. COAL	10,209	10,220	10,190	10,260	10,241	10,219
51. NATURAL GAS	7,344	7,261	7,432	7,507	7,555	7,691
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,535**	**9,119**	**9,283**	**9,177**	**9,083**	**9,230**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
56. LIGHT OIL	24.01	24.03	24.04	25.81	24.46	25.26
57. COAL	3.45	3.46	3.42	3.41	3.40	3.37
58. NATURAL GAS	4.69	4.05	4.22	4.28	4.16	4.22
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.75**	**3.69**	**3.69**	**3.76**	**3.73**	**3.71**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

SCHEDULE E3

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	99,673	78,747	113,976	78,870	91,700	81,599	1,039,658
3.	COAL	38,892,495	38,919,999	30,786,167	31,006,213	30,667,179	35,800,345	399,454,811
4.	NATURAL GAS	30,901,943	30,153,961	34,562,106	28,957,822	19,785,992	17,179,918	297,263,070
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**69,894,111**	**69,152,707**	**65,462,249**	**60,042,905**	**50,544,871**	**53,061,862**	**697,757,539**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	408	326	452	326	363	339	4,233
10.	COAL	1,131,040	1,121,820	876,320	885,750	858,300	1,016,320	11,544,670
11.	NATURAL GAS	720,382	707,384	835,108	694,384	453,377	364,821	6,973,999
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**1,851,830**	**1,829,530**	**1,711,880**	**1,580,460**	**1,312,040**	**1,381,480**	**18,522,902**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	3,500	2,450	3,580	1,560	4,300	1,580	38,850
17.	COAL (TON)	482,940	478,770	372,780	376,770	366,520	433,360	4,923,050
18.	NATURAL GAS (MCF)	5,488,140	5,299,620	6,372,950	5,167,110	3,464,380	2,693,610	51,846,020
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
21.	HEAVY OIL	0	0	0	0	0	0	0
22.	LIGHT OIL	4,380	3,500	4,860	3,500	3,900	3,640	45,510
23.	COAL	11,554,910	11,456,680	8,965,510	9,066,340	8,786,200	10,392,360	118,029,000
24.	NATURAL GAS	5,632,140	5,438,350	6,541,770	5,302,110	3,537,490	2,749,120	53,170,540
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**17,191,430**	**16,898,530**	**15,512,140**	**14,371,950**	**12,327,590**	**13,145,120**	**171,245,050**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.02	0.02	0.03	0.02	0.03	0.02	0.02
30.	COAL	61.08	61.32	51.19	56.04	65.41	73.57	62.33
31.	NATURAL GAS	38.90	38.66	48.78	43.94	34.56	26.41	37.65
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36.	LIGHT OIL ($/BBL)	28.48	32.14	31.84	50.56	21.33	51.64	26.76
37.	COAL ($/TON)	80.53	81.29	82.59	82.29	83.67	82.61	81.14
38.	NATURAL GAS ($/MCF)	5.63	5.69	5.42	5.60	5.71	6.38	5.73
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	22.76	22.50	23.45	22.53	23.51	22.42	22.84
43.	COAL	3.37	3.40	3.43	3.42	3.49	3.44	3.38
44.	NATURAL GAS	5.49	5.54	5.28	5.46	5.59	6.25	5.59
45.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**4.07**	**4.09**	**4.22**	**4.18**	**4.10**	**4.04**	**4.07**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,747	10,747	10,755	10,747	10,755	10,747	10,751
50.	COAL	10,216	10,213	10,231	10,236	10,237	10,225	10,224
51.	NATURAL GAS	7,818	7,688	7,833	7,636	7,803	7,536	7,624
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,283**	**9,237**	**9,061**	**9,094**	**9,396**	**9,515**	**9,245**
GENERATED FUEL COST PER KWH (CENTS/KWH)								
55.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56.	LIGHT OIL	24.46	24.18	25.22	24.22	25.29	24.09	24.56
57.	COAL	3.44	3.47	3.51	3.50	3.57	3.52	3.46
58.	NATURAL GAS	4.29	4.26	4.14	4.17	4.36	4.71	4.26
59.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**3.77**	**3.78**	**3.82**	**3.80**	**3.85**	**3.84**	**3.77**

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	227,690	77.5	81.0	88.7	10,075	COAL	97,880	23,436,453	2,293,960.0	7,726,846	3.39	78.94
2. B.B.#2	395	238,440	81.1	85.9	90.4	10,228	COAL	104,100	23,427,089	2,438,760.0	8,217,868	3.45	78.94
3. B.B.#3	365	217,230	80.0	88.0	88.2	10,515	COAL	97,460	23,436,795	2,284,150.0	7,693,692	3.54	78.94
4. B.B.#4	417	262,570	84.6	89.1	94.0	10,098	COAL	113,140	23,435,920	2,651,540.0	8,931,509	3.40	78.94
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	369,886	-	134.99
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,572**	**945,930**	**80.9**	**86.0**	**90.4**	**10,221**	-	-	-	-	**32,939,801**	**3.48**	-
6. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	61	1,020	2.2	-	83.6	10,961	GAS	10,890	1,026,630	11,180.0	71,354	7.00	6.55
8. B.B.C.T.#4 TOTAL	**61**	**1,020**	**2.2**	**99.4**	**83.6**	**10,961**	-	-	-	**11,180.0**	**71,354**	**7.00**	-
9. BIG BEND STATION TOTAL	**1,633**	**946,950**	**77.9**	**86.5**	**90.4**	**10,222**	-	-	-	**9,679,590.0**	**33,011,155**	**3.49**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,100,989	3.27	88.96
11. POLK #1 CT GAS	235	2,420	1.4	-	73.6	7,764	GAS	22,660	829,214	18,790.0	148,474	6.14	6.55
12. POLK #1 TOTAL	**220**	**158,410**	**96.8**	**92.8**	**98.2**	**10,099**	-	-	-	**1,599,780.0**	**5,249,463**	**3.31**	-
13. POLK #2 CT GAS	183	102	0.1	-	27.8	33,658	GAS	3,340	1,026,946	3,430.0	21,884	21.47	6.55
14. POLK #2 CT OIL	187	168	0.1	-	22.5	10,768	LGT OIL	310	5,838,710	1,810.0	40,432	24.05	130.43
15. POLK #2 TOTAL	**187**	**270**	**0.2**	**98.0**	**24.2**	**19,407**	-	-	-	**5,240.0**	**62,316**	**23.08**	-
16. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
17. POLK #3 CT OIL	187	169	0.1	-	22.6	10,727	LGT OIL	310	5,838,710	1,810.0	40,433	23.96	130.43
18. POLK #3 TOTAL	**187**	**169**	**0.1**	**98.0**	**22.6**	**10,727**	-	-	-	**1,810.0**	**40,433**	**23.96**	-
19. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**960**	**158,849**	**22.2**	**59.5**	**97.4**	**10,115**	-	-	-	**1,606,830.0**	**5,352,212**	**3.37**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	163,830	27.8	89.0	55.6	7,261	GAS	1,157,240	1,027,998	1,189,640.0	7,582,499	4.63	6.55
24. BAYSIDE #2	1,047	171,110	22.0	88.9	24.2	7,366	GAS	1,226,010	1,028,010	1,260,350.0	8,033,096	4.69	6.55
25. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
26. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
27. BAYSIDE #5	61	560	1.2	98.6	83.5	11,018	GAS	6,010	1,026,622	6,170.0	39,379	7.03	6.55
28. BAYSIDE #6	61	100	0.2	98.6	82.0	12,200	GAS	1,180	1,033,898	1,220.0	7,732	7.73	6.55
29. BAYSIDE TOTAL	**2,083**	**335,600**	**21.7**	**84.3**	**33.5**	**7,322**	**GAS**	**2,390,440**	**1,028,003**	**2,457,380.0**	**15,662,706**	**4.67**	**6.55**
30. SYSTEM	**4,676**	**1,441,399**	**41.4**	**80.0**	**65.1**	**9,535**	-	-	-	**13,743,800.0**	**54,026,073**	**3.75**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	100,530	37.9	40.5	86.6	10,106	COAL	43,350	23,435,525	1,015,930.0	3,382,959	3.37	78.04
2. B.B.#2	395	104,870	39.5	43.0	87.9	10,270	COAL	45,970	23,427,670	1,076,970.0	3,587,417	3.42	78.04
3. B.B.#3	365	203,750	83.1	88.0	91.7	10,468	COAL	91,010	23,435,666	2,132,880.0	7,102,263	3.49	78.04
4. B.B.#4	417	241,000	86.0	89.1	95.5	10,086	COAL	103,710	23,436,795	2,430,630.0	8,093,355	3.36	78.04
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	4,520	-	26,180.0	612,580	-	135.53
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,572**	**650,150**	**61.5**	**65.1**	**91.6**	**10,238**	-	-	-	-	**22,778,574**	**3.50**	-
6. B.B.C.T.#4 OIL	61	20	0.0	-	4.8	10,823	LGT OIL	40	5,500,000	220.0	5,421	26.67	135.53
7. B.B.C.T.#4 GAS	61	990	2.4	-	85.4	10,963	GAS	10,540	1,029,412	10,850.0	60,386	6.10	5.73
8. B.B.C.T.#4 TOTAL	**61**	**1,010**	**2.5**	**99.4**	**63.7**	**10,960**	-	-	-	**11,070.0**	**65,807**	**6.52**	-
9. BIG BEND STATION TOTAL	**1,633**	**651,160**	**59.3**	**66.4**	**91.5**	**10,239**	-	-	-	**6,667,480.0**	**22,844,381**	**3.51**	-
10. POLK #1 GASIFIER	220	140,990	95.4	-	98.7	10,138	COAL	51,820	27,583,558	1,429,380.0	4,615,958	3.27	89.08
11. POLK #1 CT GAS	235	2,150	1.4	-	83.2	7,637	GAS	20,350	806,880	16,420.0	116,590	5.42	5.73
12. POLK #1 TOTAL	**220**	**143,140**	**96.8**	**92.8**	**98.5**	**10,101**	-	-	-	**1,445,800.0**	**4,732,548**	**3.31**	-
13. POLK #2 CT GAS	183	2,847	2.3	-	81.9	11,734	GAS	32,500	1,028,000	33,410.0	186,201	6.54	5.73
14. POLK #2 CT OIL	187	213	0.2	-	22.7	10,768	LGT OIL	390	5,871,795	2,290.0	50,935	23.95	130.60
15. POLK #2 TOTAL	**187**	**3,060**	**2.4**	**98.0**	**69.4**	**11,667**	-	-	-	**35,700.0**	**237,136**	**7.75**	-
16. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
17. POLK #3 CT OIL	187	213	0.2	-	22.8	10,727	LGT OIL	390	5,871,795	2,290.0	50,935	23.86	130.60
18. POLK #3 TOTAL	**187**	**213**	**0.2**	**98.0**	**22.8**	**10,727**	-	-	-	**2,290.0**	**50,935**	**23.86**	-
19. POLK #4 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**960**	**146,413**	**22.7**	**59.5**	**97.1**	**10,134**	-	-	-	**1,483,790.0**	**5,020,619**	**3.43**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	300,370	56.4	89.0	68.2	7,182	GAS	2,098,610	1,027,999	2,157,370.0	12,023,467	4.00	5.73
24. BAYSIDE #2	1,047	160,170	22.8	60.3	37.0	7,235	GAS	1,127,250	1,027,971	1,158,780.0	6,458,301	4.03	5.73
25. BAYSIDE #3	61	690	1.7	98.6	87.0	11,058	GAS	7,430	1,026,918	7,630.0	42,568	6.17	5.73
26. BAYSIDE #4	61	100	0.2	98.6	82.0	11,500	GAS	0	0	1,150.0	0	0.00	0.00
27. BAYSIDE #5	61	1,180	2.9	98.6	87.9	10,839	GAS	12,450	1,027,309	12,790.0	71,329	6.04	5.73
28. BAYSIDE #6	61	960	2.3	98.6	87.4	10,823	GAS	10,110	1,027,695	10,390.0	57,923	6.03	5.73
29. BAYSIDE TOTAL	**2,083**	**463,470**	**33.1**	**75.7**	**52.8**	**7,224**	**GAS**	**3,255,850**	**1,028,337**	**3,348,110.0**	**18,653,588**	**4.02**	**5.73**
30. SYSTEM	**4,676**	**1,261,043**	**40.1**	**69.1**	**72.5**	**9,119**	-	-	-	**11,499,380.0**	**46,518,588**	**3.69**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	231,230	78.7	81.0	90.1	10,066	COAL	99,310	23,437,317	2,327,560.0	7,710,710	3.33	77.64
2. B.B.#2	395	240,020	81.7	85.9	91.0	10,223	COAL	104,740	23,427,153	2,453,760.0	8,132,308	3.39	77.64
3. B.B.#3	365	116,450	42.9	48.3	86.2	10,542	COAL	52,380	23,435,662	1,227,560.0	4,066,927	3.49	77.64
4. B.B.#4	417	238,650	76.9	80.5	94.6	10,096	COAL	102,800	23,437,938	2,409,420.0	7,981,670	3.34	77.64
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	21,030.0	493,320	-	135.90
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,572**	**826,350**	**70.7**	**74.5**	**91.0**	**10,187**	-	-	-	-	**28,384,935**	**3.43**	-
6. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	61	2,820	6.2	-	90.6	10,752	GAS	29,500	1,027,797	30,320.0	171,936	6.10	5.83
8. B.B.C.T.#4 TOTAL	**61**	**2,820**	**6.2**	**99.4**	**90.6**	**10,752**	-	-	-	**30,320.0**	**171,936**	**6.10**	-
9. BIG BEND STATION TOTAL	**1,633**	**829,170**	**68.2**	**75.5**	**91.0**	**10,189**	-	-	-	**8,448,620.0**	**28,556,871**	**3.44**	-
10. POLK #1 GASIFIER	220	85,580	52.3	-	98.7	10,213	COAL	31,460	27,781,310	874,000.0	2,822,152	3.30	89.71
11. POLK #1 CT GAS	235	3,080	1.8	-	93.6	7,247	GAS	30,470	732,524	22,320.0	177,590	5.77	5.83
12. POLK #1 TOTAL	**220**	**88,660**	**54.2**	**50.9**	**98.5**	**10,110**	-	-	-	**896,320.0**	**2,999,742**	**3.38**	-
13. POLK #2 CT GAS	183	4,218	3.1	-	92.2	11,249	GAS	46,160	1,027,946	47,450.0	269,036	6.38	5.83
14. POLK #2 CT OIL	187	212	0.2	-	22.6	10,768	LGT OIL	390	5,846,154	2,280.0	51,000	24.09	130.77
15. POLK #2 TOTAL	**187**	**4,430**	**3.2**	**98.0**	**80.4**	**11,226**	-	-	-	**49,730.0**	**320,036**	**7.22**	-
16. POLK #3 CT GAS	183	1,047	0.8	-	81.8	12,822	GAS	13,060	1,028,331	13,430.0	76,118	7.27	5.83
17. POLK #3 CT OIL	187	213	0.2	-	22.7	10,727	LGT OIL	390	5,846,154	2,280.0	51,000	23.99	130.77
18. POLK #3 TOTAL	**187**	**1,260**	**0.9**	**98.0**	**56.9**	**12,468**	-	-	-	**15,710.0**	**127,118**	**10.09**	-
19. POLK #4 CT GAS	**183**	**2,990**	**2.2**	**98.7**	**96.1**	**10,742**	**GAS**	**31,250**	**1,027,840**	**32,120.0**	**182,136**	**6.09**	**5.83**
20. POLK #5 CT GAS	**183**	**1,230**	**0.9**	**98.7**	**96.0**	**10,797**	**GAS**	**12,920**	**1,027,864**	**13,280.0**	**75,302**	**6.12**	**5.83**
21. POLK STATION TOTAL	**960**	**98,570**	**13.8**	**87.5**	**96.6**	**10,218**	-	-	-	**1,007,160.0**	**3,704,334**	**3.76**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	196,310	33.3	63.2	54.6	7,261	GAS	1,386,560	1,027,997	1,425,380.0	8,081,342	4.12	5.83
24. BAYSIDE #2	1,047	228,760	29.4	88.9	32.3	7,288	GAS	1,621,720	1,027,995	1,667,120.0	9,451,936	4.13	5.83
25. BAYSIDE #3	61	1,100	2.4	89.1	85.9	11,155	GAS	11,940	1,027,638	12,270.0	69,590	6.33	5.83
26. BAYSIDE #4	61	320	0.7	98.6	87.4	12,000	GAS	3,740	1,026,738	3,840.0	21,798	6.81	5.83
27. BAYSIDE #5	61	2,500	5.5	98.6	89.1	10,772	GAS	26,200	1,027,863	26,930.0	152,702	6.11	5.83
28. BAYSIDE #6	61	2,360	5.2	98.6	87.9	10,809	GAS	24,820	1,027,800	25,510.0	144,659	6.13	5.83
29. BAYSIDE TOTAL	**2,083**	**431,350**	**27.8**	**80.0**	**40.1**	**7,328**	**GAS**	**3,074,980**	**1,027,990**	**3,161,050.0**	**17,922,027**	**4.15**	**5.83**
30. SYSTEM	**4,676**	**1,359,090**	**39.1**	**79.9**	**65.1**	**9,283**	-	-	-	**12,616,830.0**	**50,183,232**	**3.69**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	222,490	80.3	81.0	91.9	10,145	COAL	96,310	23,436,611	2,257,180.0	7,447,070	3.35	77.32
2. B.B.#2	385	232,850	84.0	85.9	93.5	10,233	COAL	101,700	23,428,417	2,382,670.0	7,863,850	3.38	77.32
3. B.B.#3	365	221,120	84.1	88.0	92.8	10,489	COAL	98,960	23,436,439	2,319,270.0	7,651,976	3.46	77.32
4. B.B.#4	407	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,670	-	15,450.0	363,477	-	136.13
B.B. IGNITION	-	-	-	-	-	-	GAS	0	-	0.0	0	-	0.00
5. B.B. COAL	**1,542**	**676,460**	**60.9**	**62.5**	**92.7**	**10,288**	-	-	-	-	**23,326,373**	**3.45**	-
6. B.B.C.T.#4 OIL	56	28	0.1	-	16.5	10,823	LGT OIL	50	6,000,000	300.0	10,007	36.10	200.14
7. B.B.C.T.#4 GAS	56	2,322	5.8	-	92.2	11,131	GAS	25,140	1,028,242	25,850.0	147,343	6.34	5.86
8. B.B.C.T.#4 TOTAL	**56**	**2,350**	**5.8**	**82.9**	**67.4**	**11,128**	-	-	-	**26,150.0**	**157,350**	**6.70**	-
9. BIG BEND STATION TOTAL	**1,598**	**678,810**	**59.0**	**63.2**	**92.7**	**10,290**	-	-	-	**6,985,270.0**	**23,483,723**	**3.46**	-
10. POLK #1 GASIFIER	220	150,980	95.3	-	98.7	10,136	COAL	55,500	27,573,874	1,530,350.0	4,916,165	3.26	88.58
11. POLK #1 CT GAS	218	3,480	2.2	-	99.8	7,253	GAS	28,930	872,451	25,240.0	169,556	4.87	5.86
12. POLK #1 TOTAL	**220**	**154,460**	**97.5**	**92.8**	**98.6**	**10,071**	-	-	-	**1,555,590.0**	**5,085,721**	**3.29**	-
13. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
14. POLK #2 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
15. POLK #2 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**	-	-	-	**0.0**	**0**	**0.00**	-
16. POLK #3 CT GAS	151	7,427	6.8	-	94.6	11,302	GAS	81,660	1,027,921	83,940.0	478,602	6.44	5.86
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,249	24.06	130.83
18. POLK #3 TOTAL	**159**	**7,590**	**6.6**	**98.0**	**89.4**	**11,290**	-	-	-	**65,690.0**	**517,851**	**6.82**	-
19. POLK #4 CT GAS	**151**	**3,680**	**3.4**	**98.7**	**97.5**	**10,995**	**GAS**	**39,360**	**1,027,947**	**40,460.0**	**230,685**	**6.27**	**5.86**
20. POLK #5 CT GAS	**151**	**2,420**	**2.2**	**98.7**	**100.2**	**11,062**	**GAS**	**26,040**	**1,028,034**	**26,770.0**	**152,618**	**6.31**	**5.86**
21. POLK STATION TOTAL	**840**	**166,150**	**27.8**	**78.4**	**98.3**	**10,161**	-	-	-	**1,708,510.0**	**5,986,875**	**3.56**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	168,470	33.4	89.0	54.9	7,355	GAS	1,205,320	1,028,017	1,239,090.0	7,064,268	4.19	5.86
24. BAYSIDE #2	929	344,130	51.4	88.9	56.6	7,361	GAS	2,464,120	1,028,006	2,533,130.0	14,441,977	4.20	5.86
25. BAYSIDE #3	56	590	1.5	92.0	95.8	11,186	GAS	6,420	1,028,037	6,600.0	37,627	6.38	5.86
26. BAYSIDE #4	56	660	1.6	82.2	90.7	11,121	GAS	7,150	1,026,573	7,340.0	41,905	6.35	5.86
27. BAYSIDE #5	56	2,270	5.6	82.2	92.1	11,119	GAS	24,550	1,028,106	25,240.0	143,885	6.34	5.86
28. BAYSIDE #6	56	1,600	4.0	82.2	92.2	11,188	GAS	17,410	1,028,145	17,900.0	102,038	6.38	5.86
29. BAYSIDE TOTAL	**1,854**	**517,720**	**38.8**	**88.4**	**56.3**	**7,396**	**GAS**	**3,724,970**	**1,028,008**	**3,829,300.0**	**21,831,700**	**4.22**	**5.86**
30. SYSTEM	**4,292**	**1,364,680**	**44.2**	**77.1**	**74.8**	**9,177**	-	-	-	**12,523,080.0**	**51,302,298**	**3.76**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	231,710	80.9	81.0	92.6	10,136	COAL	100,210	23,436,483	2,348,570.0	7,732,186	3.34	77.16
2. B.B.#2	385	243,730	85.1	85.9	94.8	10,214	COAL	106,260	23,427,066	2,489,360.0	8,198,999	3.36	77.16
3. B.B.#3	365	232,220	85.5	88.0	94.3	10,469	COAL	103,730	23,436,229	2,431,040.0	8,003,790	3.45	77.16
4. B.B.#4	407	66,760	22.0	23.0	94.8	10,160	COAL	28,940	23,438,493	678,310.0	2,233,003	3.34	77.16
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	373,540	-	136.33
B.B. IGNITION	-	-	-	-	-	-	GAS	10,020	-	10,300.0	56,692	-	5.66
5. B.B. COAL	**1,542**	**774,420**	**67.5**	**68.6**	**94.0**	**10,262**	-	-	-	-	**26,598,210**	**3.43**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	5,450	13.1	-	93.6	10,994	GAS	58,280	1,028,140	59,920.0	329,743	6.05	5.66
8. B.B.C.T.#4 TOTAL	**56**	**5,450**	**13.1**	**99.4**	**93.6**	**10,994**	-	-	-	**59,920.0**	**329,743**	**6.05**	-
9. BIG BEND STATION TOTAL	**1,598**	**779,870**	**65.6**	**69.7**	**94.0**	**10,267**	-	-	-	**8,007,200.0**	**26,927,953**	**3.45**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,375	1,581,000.0	5,063,596	3.25	88.31
11. POLK #1 CT GAS	218	3,390	2.1	-	97.2	7,280	GAS	28,390	869,320	24,680.0	160,628	4.74	5.66
12. POLK #1 TOTAL	**220**	**159,380**	**97.4**	**92.8**	**98.7**	**10,075**	-	-	-	**1,605,680.0**	**5,224,224**	**3.28**	-
13. POLK #2 CT GAS	151	11,037	9.8	-	94.9	11,273	GAS	121,030	1,028,010	124,420.0	684,775	6.20	5.66
14. POLK #2 CT OIL	159	203	0.2	-	25.6	10,768	LGT OIL	380	5,763,158	2,190.0	49,743	24.46	130.90
15. POLK #2 TOTAL	**159**	**11,240**	**9.5**	**98.0**	**90.5**	**11,264**	-	-	-	**126,610.0**	**734,518**	**6.53**	-
16. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
17. POLK #3 CT OIL	159	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
16. POLK #3 TOTAL	**159**	**0**	**0.0**	**0.0**	**0.0**	**0**	-	-	-	**0.0**	**0**	**0.00**	-
19. POLK #4 CT GAS	**151**	**8,820**	**7.9**	**98.7**	**97.4**	**11,009**	**GAS**	**94,450**	**1,028,057**	**97,100.0**	**534,389**	**6.06**	**5.66**
20. POLK #5 CT GAS	**151**	**4,800**	**4.3**	**98.7**	**99.3**	**10,979**	**GAS**	**51,270**	**1,027,892**	**52,700.0**	**290,081**	**6.04**	**5.66**
21. POLK STATION TOTAL	**840**	**184,240**	**29.5**	**78.4**	**98.1**	**10,215**	-	-	-	**1,882,090.0**	**6,783,212**	**3.68**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	252,720	48.5	89.0	56.7	7,355	GAS	1,808,110	1,027,991	1,858,720.0	10,230,107	4.05	5.66
24. BAYSIDE #2	929	406,900	58.9	88.9	64.8	7,320	GAS	2,897,240	1,028,006	2,978,380.0	16,392,297	4.03	5.66
25. BAYSIDE #3	56	1,800	4.3	98.6	91.8	11,183	GAS	19,580	1,028,090	20,130.0	110,782	6.15	5.66
26. BAYSIDE #4	56	820	2.0	98.6	91.5	11,220	GAS	8,960	1,026,786	9,200.0	50,695	6.18	5.66
27. BAYSIDE #5	56	5,110	12.3	98.6	93.1	10,994	GAS	54,660	1,027,808	56,180.0	309,261	6.05	5.66
28. BAYSIDE #6	56	3,740	9.0	98.6	92.8	11,070	GAS	40,280	1,027,805	41,400.0	227,900	6.09	5.66
29. BAYSIDE TOTAL	**1,854**	**671,090**	**48.7**	**90.1**	**61.8**	**7,397**	**GAS**	**4,828,830**	**1,027,994**	**4,964,010.0**	**27,321,042**	**4.07**	**5.66**
30. SYSTEM	**4,292**	**1,635,200**	**51.2**	**80.2**	**77.7**	**9,083**	-	-	-	**14,853,300.0**	**61,032,207**	**3.73**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	223,860	80.8	81.0	92.4	10,137	COAL	96,820	23,437,203	2,269,190.0	7,458,902	3.33	77.04
2. B.B.#2	385	235,540	85.0	85.9	94.6	10,215	COAL	102,700	23,428,432	2,406,100.0	7,911,889	3.36	77.04
3. B.B.#3	365	224,370	85.4	88.0	94.1	10,471	COAL	100,240	23,437,450	2,349,370.0	7,722,373	3.44	77.04
4. B.B.#4	407	257,520	87.9	89.1	97.6	10,122	COAL	111,230	23,435,045	2,606,680.0	8,569,028	3.33	77.04
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,850	-	10,730.0	252,417	-	136.44
B.B. IGNITION	-	-	-	-	-	-	GAS	4,460	-	5,150.0	25,130	-	5.63
5. B.B. COAL	**1,542**	**941,290**	**84.8**	**86.1**	**94.8**	**10,232**	-	-	-	-	**31,939,739**	**3.39**	-
6. B.B.C.T.#4 OIL	56	53	0.1	-	15.7	10,823	LGT OIL	100	5,700,000	570.0	16,844	31.98	168.44
7. B.B.C.T.#4 GAS	56	4,897	12.1	-	92.1	11,159	GAS	53,160	1,028,029	54,650.0	299,528	6.12	5.63
8. B.B.C.T.#4 TOTAL	**56**	**4,950**	**12.3**	**99.4**	**87.5**	**11,156**	-	-	-	**55,220.0**	**316,372**	**6.39**	-
9. BIG BEND STATION TOTAL	**1,598**	**946,240**	**82.2**	**86.5**	**94.7**	**10,237**	-	-	-	**9,686,560.0**	**32,256,111**	**3.41**	-
10. POLK #1 GASIFIER	220	150,990	95.3	-	98.8	10,136	COAL	55,500	27,575,135	1,530,420.0	4,895,921	3.24	88.21
11. POLK #1 CT GAS	218	3,500	2.2	-	100.3	7,346	GAS	29,380	875,085	25,710.0	165,540	4.73	5.63
12. POLK #1 TOTAL	**220**	**154,490**	**97.5**	**92.8**	**98.8**	**10,073**	-	-	-	**1,556,130.0**	**5,061,461**	**3.28**	-
13. POLK #2 CT GAS	151	18,617	17.1	-	96.3	11,195	GAS	202,740	1,028,016	208,420.0	1,142,332	6.14	5.63
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,306	24.19	131.02
15. POLK #2 TOTAL	**159**	**18,780**	**16.4**	**98.0**	**94.1**	**11,191**	-	-	-	**210,170.0**	**1,181,638**	**8.29**	-
16. POLK #3 CT GAS	151	12,156	11.2	-	95.8	11,228	GAS	132,770	1,028,018	136,490.0	748,087	6.15	5.63
17. POLK #3 CT OIL	159	204	0.2	-	25.7	10,727	LGT OIL	380	5,763,158	2,190.0	49,788	24.39	131.02
18. POLK #3 TOTAL	**159**	**12,360**	**10.8**	**98.0**	**91.7**	**11,220**	-	-	-	**138,680.0**	**797,875**	**6.46**	-
19. POLK #4 CT GAS	**151**	**10,400**	**9.6**	**98.7**	**98.4**	**11,117**	**GAS**	**112,480**	**1,027,916**	**115,620.0**	**633,764**	**6.09**	**5.63**
20. POLK #5 CT GAS	**151**	**6,320**	**5.8**	**98.7**	**99.7**	**11,125**	**GAS**	**68,400**	**1,027,924**	**70,310.0**	**385,397**	**6.10**	**5.63**
21. POLK STATION TOTAL	**840**	**202,350**	**33.5**	**96.9**	**97.9**	**10,333**	-	-	-	**2,090,910.0**	**8,060,135**	**3.98**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	248,270	49.2	89.0	58.3	7,369	GAS	1,779,760	1,027,998	1,829,590.0	10,027,988	4.04	5.63
24. BAYSIDE #2	929	384,770	57.5	88.9	63.3	7,316	GAS	2,738,250	1,027,996	2,814,910.0	15,428,564	4.01	5.63
25. BAYSIDE #3	56	2,600	6.4	98.6	92.9	11,142	GAS	28,180	1,028,034	28,970.0	158,779	6.11	5.63
26. BAYSIDE #4	56	1,480	3.7	98.6	94.4	11,230	GAS	15,570	1,067,437	16,620.0	87,729	5.93	5.63
27. BAYSIDE #5	56	4,670	11.6	98.6	92.7	11,015	GAS	50,040	1,027,978	51,440.0	281,948	6.04	5.63
28. BAYSIDE #6	56	3,890	9.6	98.6	92.6	11,028	GAS	41,740	1,027,791	42,900.0	235,182	6.05	5.63
29. BAYSIDE TOTAL	**1,854**	**645,680**	**48.4**	**90.1**	**61.7**	**7,410**	**GAS**	**4,653,540**	**1,026,127**	**4,784,430.0**	**26,220,190**	**4.06**	**5.63**
30. SYSTEM	**4,292**	**1,794,270**	**58.1**	**90.1**	**79.7**	**9,230**	-	-	-	**16,561,900.0**	**66,536,436**	**3.71**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] City of Tampa on long term reserve standby.

[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	231,750	80.9	81.0	92.6	10,135	COAL	100,220	23,435,642	2,348,720.0	7,870,243	3.40	78.53
2. B.B.#2	385	243,960	85.2	85.9	94.9	10,211	COAL	106,330	23,428,571	2,491,160.0	8,350,052	3.42	78.53
3. B.B.#3	365	232,290	85.5	88.0	94.3	10,468	COAL	103,750	23,437,590	2,431,650.0	8,147,453	3.51	78.53
4. B.B.#4	407	267,050	88.2	89.1	97.9	10,119	COAL	115,300	23,437,901	2,702,390.0	9,054,466	3.39	78.53
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	374,221	-	136.58
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	28,235	-	5.64
5. B.B. COAL	**1,542**	**975,050**	**85.0**	**86.1**	**95.0**	**10,229**	-	-	-	-	**33,824,670**	**3.47**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	6,060	14.5	-	95.8	10,975	GAS	64,700	1,027,975	66,510.0	364,638	6.02	5.64
8. B.B.C.T.#4 TOTAL	**56**	**6,060**	**14.5**	**99.4**	**95.8**	**10,975**	-	-	-	**66,510.0**	**364,638**	**6.02**	-
9. BIG BEND STATION TOTAL	**1,598**	**981,110**	**82.5**	**86.5**	**95.0**	**10,234**	-	-	-	**10,040,430.0**	**34,189,308**	**3.48**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,067,825	3.25	88.38
11. POLK #1 CT GAS	218	2,420	1.5	-	100.9	7,438	GAS	21,890	822,293	18,000.0	123,368	5.10	5.64
12. POLK #1 TOTAL	**220**	**158,410**	**96.8**	**92.8**	**98.8**	**10,094**	-	-	-	**1,598,990.0**	**5,191,193**	**3.26**	-
13. POLK #2 CT GAS	151	20,927	18.6	-	94.3	11,174	GAS	227,460	1,028,005	233,830.0	1,281,924	6.13	5.64
14. POLK #2 CT OIL	159	203	0.2	-	25.6	10,768	LGT OIL	380	5,763,158	2,190.0	49,837	24.50	131.15
15. POLK #2 TOTAL	**159**	**21,130**	**17.9**	**98.0**	**91.9**	**11,170**	-	-	-	**236,020.0**	**1,331,761**	**6.30**	-
16. POLK #3 CT GAS	151	18,376	16.4	-	95.8	11,171	GAS	199,690	1,027,943	205,270.0	1,125,417	6.12	5.64
17. POLK #3 CT OIL	159	204	0.2	-	25.7	10,727	LGT OIL	380	5,763,158	2,190.0	49,836	24.41	131.15
18. POLK #3 TOTAL	**159**	**18,580**	**15.7**	**98.0**	**93.0**	**11,166**	-	-	-	**207,460.0**	**1,175,253**	**6.33**	-
19. POLK #4 CT GAS	**151**	**16,460**	**14.7**	**98.7**	**98.2**	**10,967**	**GAS**	**175,610**	**1,027,960**	**180,520.0**	**989,707**	**6.01**	**5.64**
20. POLK #5 CT GAS	**151**	**13,680**	**12.2**	**98.7**	**98.5**	**11,050**	**GAS**	**147,070**	**1,027,878**	**151,170.0**	**828,860**	**6.08**	**5.64**
21. POLK STATION TOTAL	**840**	**228,260**	**36.5**	**96.9**	**97.6**	**10,401**	-	-	-	**2,374,160.0**	**9,516,774**	**4.17**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	244,650	46.9	89.0	55.4	7,380	GAS	1,756,330	1,028,002	1,805,510.0	9,898,363	4.05	5.64
24. BAYSIDE #2	929	382,920	55.4	88.9	61.0	7,332	GAS	2,731,060	1,028,004	2,807,540.0	15,391,767	4.02	5.64
25. BAYSIDE #3	56	3,400	8.2	98.6	94.9	11,029	GAS	36,480	1,027,961	37,500.0	205,595	6.05	5.64
26. BAYSIDE #4	56	2,100	5.0	98.6	96.2	11,143	GAS	22,760	1,028,120	23,400.0	128,271	6.11	5.64
27. BAYSIDE #5	56	5,040	12.1	98.6	95.7	10,948	GAS	53,670	1,028,135	55,180.0	302,475	6.00	5.64
28. BAYSIDE #6	56	4,350	10.4	98.6	95.9	10,968	GAS	46,410	1,028,011	47,710.0	261,558	6.01	5.64
29. BAYSIDE TOTAL	**1,854**	**642,460**	**46.8**	**90.1**	**59.2**	**7,435**	**GAS**	**4,646,710**	**1,028,005**	**4,778,840.0**	**26,188,029**	**4.08**	**5.64**
30. SYSTEM	**4,292**	**1,851,830**	**58.0**	**90.1**	**78.7**	**9,283**	-	-	-	**17,191,430.0**	**69,894,111**	**3.77**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] City of Tampa on long term reserve standby.

[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	217,190	75.8	75.8	92.8	10,133	COAL	93,910	23,435,630	2,200,840.0	7,483,797	3.45	79.69
2. B.B.#2	385	244,850	85.5	85.9	95.2	10,208	COAL	106,690	23,426,844	2,499,410.0	8,502,254	3.47	79.69
3. B.B.#3	365	235,850	86.9	88.0	95.7	10,451	COAL	105,170	23,436,246	2,464,790.0	8,381,124	3.55	79.69
4. B.B.#4	407	267,940	88.5	89.1	98.3	10,117	COAL	115,660	23,436,365	2,710,650.0	9,217,079	3.44	79.69
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	1,850	-	10,730.0	252,817	-	136.66
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	28,533	-	5.70
5. B.B. COAL	**1,542**	**965,830**	**84.2**	**84.8**	**95.6**	**10,225**	-	-	-	-	**33,865,604**	**3.51**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	7,250	17.4	-	94.5	11,001	GAS	77,580	1,028,100	79,760.0	441,835	6.09	5.70
8. B.B.C.T.#4 TOTAL	**56**	**7,250**	**17.4**	**99.4**	**94.5**	**11,001**	-	-	-	**79,760.0**	**441,835**	**6.09**	-
9. BIG BEND STATION TOTAL	**1,598**	**973,080**	**81.8**	**85.3**	**95.6**	**10,231**	-	-	-	**9,955,450.0**	**34,307,439**	**3.53**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,054,395	3.24	88.15
11. POLK #1 CT GAS	218	0	0.0	-	0.0	0	GAS	4,380	0	0.0	24,945	0.00	5.70
12. POLK #1 TOTAL	**220**	**155,990**	**95.3**	**92.8**	**98.8**	**10,135**	-	-	-	**1,580,990.0**	**5,079,340**	**3.26**	-
13. POLK #2 CT GAS	151	23,167	20.6	-	94.7	11,230	GAS	253,090	1,027,974	260,170.0	1,441,403	6.22	5.70
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,373	24.23	131.24
15. POLK #2 TOTAL	**159**	**23,330**	**19.7**	**98.0**	**93.0**	**11,227**	-	-	-	**261,920.0**	**1,480,776**	**6.35**	-
16. POLK #3 CT GAS	151	16,697	14.9	-	97.9	11,174	GAS	181,490	1,027,991	186,570.0	1,033,625	6.19	5.70
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,374	24.13	131.25
18. POLK #3 TOTAL	**159**	**16,860**	**14.3**	**98.0**	**95.3**	**11,170**	-	-	-	**188,320.0**	**1,072,999**	**8.36**	-
19. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
20. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**840**	**196,180**	**31.4**	**61.4**	**97.7**	**10,354**	-	-	-	**2,031,230.0**	**7,633,115**	**3.89**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	239,900	46.0	89.0	52.9	7,372	GAS	1,720,320	1,028,006	1,768,500.0	9,797,598	4.08	5.70
24. BAYSIDE #2	929	402,730	58.3	88.9	64.1	7,322	GAS	2,868,660	1,027,999	2,948,980.0	16,337,646	4.06	5.70
25. BAYSIDE #3	56	3,780	9.1	98.6	96.4	11,016	GAS	40,510	1,027,894	41,640.0	230,713	6.10	5.70
26. BAYSIDE #4	56	2,180	5.2	98.6	97.3	11,083	GAS	23,500	1,028,085	24,160.0	133,838	6.14	5.70
27. BAYSIDE #5	56	6,370	15.3	98.6	94.8	10,995	GAS	68,140	1,027,884	70,040.0	388,072	6.09	5.70
28. BAYSIDE #6	56	5,310	12.7	98.6	94.8	11,023	GAS	56,940	1,027,924	58,530.0	324,286	6.11	5.70
29. BAYSIDE TOTAL	**1,854**	**660,270**	**47.9**	**90.1**	**60.0**	**7,439**	**GAS**	**4,778,070**	**1,027,999**	**4,911,850.0**	**27,212,153**	**4.12**	**5.70**
30. SYSTEM	**4,292**	**1,829,530**	**57.3**	**82.7**	**78.9**	**9,237**	-	-	-	**16,898,530.0**	**69,152,707**	**3.78**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
Document No. 3, Page 17 of 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. B.B.#2	385	237,170	85.6	85.9	95.2	10,209	COAL	103,350	23,428,060	2,421,290.0	8,306,466	3.50	80.37
3. B.B.#3	365	228,540	87.0	88.0	95.9	10,448	COAL	101,880	23,437,181	2,387,780.0	8,188,315	3.58	80.37
4. B.B.#4	407	259,570	88.6	89.1	98.4	10,115	COAL	112,030	23,436,847	2,625,630.0	9,004,092	3.47	80.37
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	2,740	-	15,880.0	374,721	-	136.76
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	27,192	-	5.43
5. B.B. COAL	**1,542**	**725,280**	**65.3**	**65.6**	**96.6**	**10,251**	-	-	-	-	**25,900,786**	**3.57**	-
6. B.B.C.T.#4 OIL	56	44	0.1	-	15.8	10,823	LGT OIL	80	6,000,000	480.0	14,141	31.89	176.76
7. B.B.C.T.#4 GAS	56	7,786	19.3	-	91.5	11,101	GAS	84,080	1,027,950	86,430.0	456,346	5.86	5.43
8. B.B.C.T.#4 TOTAL	**56**	**7,830**	**19.4**	**99.4**	**89.1**	**11,100**	-	-	-	**88,910.0**	**470,487**	**6.01**	-
9. BIG BEND STATION TOTAL	**1,598**	**733,110**	**63.7**	**67.0**	**96.5**	**10,260**	-	-	-	**7,521,610.0**	**26,371,273**	**3.60**	-
10. POLK #1 GASIFIER	220	151,040	95.4	-	98.8	10,135	COAL	55,520	27,572,226	1,530,810.0	4,885,381	3.23	87.99
11. POLK #1 CT GAS	218	0	0.0	-	0.0	0	GAS	4,380	0	0.0	23,773	0.00	5.43
12. POLK #1 TOTAL	**220**	**151,040**	**95.4**	**92.8**	**98.8**	**10,135**	-	-	-	**1,530,810.0**	**4,909,154**	**3.25**	-
13. POLK #2 CT GAS	151	32,747	30.1	-	94.7	11,127	GAS	354,460	1,027,986	364,380.0	1,923,838	5.87	5.43
14. POLK #2 CT OIL	159	203	0.2	-	25.6	10,768	LGT OIL	380	5,763,158	2,190.0	49,917	24.54	131.36
15. POLK #2 TOTAL	**159**	**32,950**	**28.8**	**98.0**	**93.1**	**11,125**	-	-	-	**366,570.0**	**1,973,755**	**5.99**	-
16. POLK #3 CT GAS	151	26,906	24.7	-	96.3	11,110	GAS	290,770	1,028,029	298,920.0	1,578,159	5.87	5.43
17. POLK #3 CT OIL	159	204	0.2	-	25.7	10,727	LGT OIL	380	5,763,158	2,190.0	49,918	24.45	131.36
18. POLK #3 TOTAL	**159**	**27,110**	**23.7**	**98.0**	**94.4**	**11,107**	-	-	-	**301,110.0**	**1,628,077**	**8.01**	-
19. POLK #4 CT GAS	**151**	**19,580**	**18.0**	**49.4**	**99.0**	**10,958**	**GAS**	**208,700**	**1,028,031**	**214,550.0**	**1,132,723**	**5.79**	**5.43**
20. POLK #5 CT GAS	**151**	**13,170**	**12.1**	**49.4**	**99.1**	**11,092**	**GAS**	**142,100**	**1,028,008**	**146,080.0**	**771,250**	**5.86**	**5.43**
21. POLK STATION TOTAL	**840**	**243,850**	**40.3**	**79.2**	**97.5**	**10,495**	-	-	-	**2,559,120.0**	**10,414,959**	**4.27**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	288,940	57.2	89.0	62.7	7,318	GAS	2,056,720	1,028,006	2,114,320.0	11,162,884	3.86	5.43
24. BAYSIDE #2	929	426,840	63.8	88.9	70.3	7,278	GAS	3,021,840	1,028,003	3,106,460.0	16,401,090	3.84	5.43
25. BAYSIDE #3	56	3,870	9.6	98.6	96.0	11,023	GAS	41,500	1,027,952	42,660.0	225,242	5.82	5.43
26. BAYSIDE #4	56	2,080	5.2	98.6	97.7	10,981	GAS	22,210	1,028,366	22,840.0	120,545	5.80	5.43
27. BAYSIDE #5	56	7,110	17.6	98.6	92.7	11,010	GAS	76,150	1,027,971	78,280.0	413,305	5.81	5.43
28. BAYSIDE #6	56	6,080	15.1	98.6	94.4	10,995	GAS	65,030	1,027,987	66,850.0	352,951	5.81	5.43
29. BAYSIDE TOTAL	**1,854**	**734,920**	**55.1**	**90.1**	**67.5**	**7,390**	**GAS**	**5,283,450**	**1,028,004**	**5,431,410.0**	**28,676,017**	**3.90**	**5.43**
30. SYSTEM	**4,292**	**1,711,880**	**55.4**	**79.4**	**81.6**	**9,061**	-	-	-	**15,512,140.0**	**65,462,249**	**3.82**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. B.B.#2	385	228,630	79.8	80.4	95.0	10,211	COAL	99,650	23,426,693	2,334,470.0	8,051,037	3.52	80.79
3. B.B.#3	365	233,720	86.1	88.0	94.9	10,462	COAL	104,330	23,436,020	2,445,080.0	8,429,146	3.61	80.79
4. B.B.#4	407	267,410	88.3	89.1	98.1	10,119	COAL	115,450	23,436,986	2,705,800.0	9,327,564	3.49	80.79
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	960	-	5,580.0	131,316	-	136.79
B.B. IGNITION	-	-	-	-	-	-	GAS	5,010	-	5,150.0	28,105	-	5.61
5. B.B. COAL	**1,542**	**729,760**	**63.6**	**64.4**	**96.1**	**10,257**	-	-	-	-	**25,967,168**	**3.56**	-
6. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	56	5,460	13.1	-	93.8	10,949	GAS	58,160	1,027,854	59,780.0	326,260	5.98	5.61
8. B.B.C.T.#4 TOTAL	**56**	**5,460**	**13.1**	**99.4**	**93.8**	**10,949**	-	-	-	**59,780.0**	**326,260**	**5.98**	-
9. BIG BEND STATION TOTAL	**1,598**	**735,220**	**61.8**	**65.7**	**96.0**	**10,262**	-	-	-	**7,545,130.0**	**26,293,428**	**3.58**	-
10. POLK #1 GASIFIER	220	155,990	95.3	-	98.8	10,135	COAL	57,340	27,572,201	1,580,990.0	5,039,045	3.23	87.88
11. POLK #1 CT GAS	218	3,390	2.1	-	97.2	7,398	GAS	28,770	871,741	25,080.0	161,391	4.76	5.61
12. POLK #1 TOTAL	**220**	**159,380**	**97.4**	**92.8**	**98.7**	**10,077**	-	-	-	**1,606,070.0**	**5,200,436**	**3.26**	-
13. POLK #2 CT GAS	151	17,287	15.4	-	94.6	11,204	GAS	188,410	1,028,024	193,690.0	1,056,924	6.11	5.61
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,435	24.26	131.45
15. POLK #2 TOTAL	**159**	**17,450**	**14.8**	**98.0**	**92.3**	**11,200**	-	-	-	**195,440.0**	**1,096,359**	**8.28**	-
16. POLK #3 CT GAS	151	9,947	8.9	-	95.5	11,309	GAS	109,440	1,027,869	112,490.0	613,925	6.17	5.61
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,435	24.17	131.45
18. POLK #3 TOTAL	**159**	**10,110**	**8.5**	**98.0**	**91.5**	**11,300**	-	-	-	**114,240.0**	**653,360**	**6.46**	-
19. POLK #4 CT GAS	**151**	**6,590**	**5.9**	**98.7**	**97.0**	**11,106**	**GAS**	**71,200**	**1,027,949**	**73,190.0**	**399,410**	**6.06**	**5.61**
20. POLK #5 CT GAS	**151**	**2,570**	**2.3**	**98.7**	**100.1**	**11,027**	**GAS**	**27,560**	**1,028,302**	**28,340.0**	**154,603**	**6.02**	**5.61**
21. POLK STATION TOTAL	**840**	**196,100**	**31.4**	**96.9**	**97.7**	**10,287**	-	-	-	**2,017,280.0**	**7,504,168**	**3.83**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	238,810	45.8	89.0	57.9	7,350	GAS	1,707,480	1,027,994	1,755,280.0	9,578,447	4.01	5.61
24. BAYSIDE #2	929	396,000	57.3	88.9	63.1	7,312	GAS	2,816,570	1,028,002	2,895,440.0	15,800,108	3.99	5.61
25. BAYSIDE #3	56	3,390	8.1	98.6	91.7	11,189	GAS	36,910	1,027,635	37,930.0	207,054	6.11	5.61
26. BAYSIDE #4	56	1,480	3.6	98.6	91.1	11,345	GAS	16,330	1,028,169	16,790.0	91,606	6.19	5.61
27. BAYSIDE #5	56	5,000	12.0	98.6	93.0	10,988	GAS	53,450	1,027,877	54,940.0	299,838	6.00	5.61
28. BAYSIDE #6	56	4,460	10.7	98.6	92.6	11,022	GAS	47,820	1,028,022	49,160.0	268,256	6.01	5.61
29. BAYSIDE TOTAL	**1,854**	**649,140**	**47.1**	**90.1**	**61.5**	**7,409**	**GAS**	**4,678,580**	**1,027,996**	**4,809,540.0**	**26,245,309**	**4.04**	**5.61**
30. SYSTEM	**4,292**	**1,580,460**	**49.5**	**82.3**	**78.2**	**9,094**	-	-	-	**14,371,950.0**	**60,042,905**	**3.80**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] City of Tampa on long term reserve standby.

[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2014

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	385	167,610	60.5	62.1	90.3	10,166	COAL	72,700	23,436,589	1,703,840.0	5,904,985	3.52	81.22
2. B.B.#2	385	167,340	60.4	63.0	91.7	10,258	COAL	73,270	23,428,961	1,716,640.0	5,951,285	3.56	81.22
3. B.B.#3	365	143,460	54.6	58.7	90.4	10,519	COAL	64,390	23,436,558	1,509,080.0	5,230,008	3.65	81.22
4. B.B.#4	407	254,090	86.7	89.1	96.3	10,139	COAL	109,920	23,438,046	2,576,310.0	8,928,142	3.51	81.22
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	3,630	-	21,030.0	496,824	-	136.87
B.B. IGNITION	-	-	-	-	-	-	GAS	14,500	-	15,450.0	83,161	-	5.74
5. B.B. COAL	**1,542**	**732,500**	**66.0**	**68.7**	**92.7**	**10,247**	-	-	-	-	**26,594,405**	**3.63**	-
6. B.B.C.T.#4 OIL	56	37	0.1	-	16.5	10,823	LGT OIL	70	5,714,286	400.0	12,781	34.58	182.59
7. B.B.C.T.#4 GAS	56	3,883	9.6	-	91.2	11,205	GAS	42,320	1,028,119	43,510.0	242,717	6.25	5.74
8. B.B.C.T.#4 TOTAL	**56**	**3,920**	**9.7**	**99.4**	**87.5**	**11,202**	-	-	-	**43,910.0**	**255,498**	**6.52**	-
9. BIG BEND STATION TOTAL	**1,598**	**736,420**	**64.0**	**69.7**	**92.6**	**10,252**	-	-	-	**7,549,780.0**	**26,849,903**	**3.65**	-
10. POLK #1 GASIFIER	220	125,800	79.4	-	98.8	10,178	COAL	46,240	27,688,798	1,280,330.0	4,072,774	3.24	88.08
11. POLK #1 CT GAS	218	6,210	4.0	-	98.2	7,287	GAS	52,760	857,657	45,250.0	302,593	4.87	5.74
12. POLK #1 TOTAL	**220**	**132,010**	**83.3**	**77.3**	**98.7**	**10,042**	-	-	-	**1,325,580.0**	**4,375,367**	**3.31**	-
13. POLK #2 CT GAS	151	14,827	13.6	-	91.8	11,281	GAS	162,710	1,028,025	167,270.0	933,186	6.29	5.74
14. POLK #2 CT OIL	159	163	0.1	-	25.6	10,768	LGT OIL	300	5,833,333	1,750.0	39,459	24.28	131.53
15. POLK #2 TOTAL	**159**	**14,990**	**13.1**	**88.2**	**89.3**	**11,278**	-	-	-	**169,020.0**	**972,645**	**8.49**	-
16. POLK #3 CT GAS	151	11,937	11.0	-	91.9	11,403	GAS	132,410	1,028,019	136,120.0	759,407	6.36	5.74
17. POLK #3 CT OIL	159	163	0.1	-	25.7	10,727	LGT OIL	300	5,833,333	1,750.0	39,460	24.19	131.53
18. POLK #3 TOTAL	**159**	**12,100**	**10.6**	**88.2**	**88.8**	**11,394**	-	-	-	**137,870.0**	**798,867**	**8.60**	-
19. POLK #4 CT GAS	**151**	**7,080**	**6.5**	**98.7**	**97.7**	**11,068**	**GAS**	**76,220**	**1,028,077**	**78,360.0**	**437,142**	**6.17**	**5.74**
20. POLK #5 CT GAS	**151**	**4,960**	**4.6**	**98.7**	**99.5**	**11,058**	**GAS**	**53,360**	**1,027,924**	**54,850.0**	**306,034**	**6.17**	**5.74**
21. POLK STATION TOTAL	**640**	**171,140**	**28.3**	**89.2**	**97.0**	**10,317**	-	-	-	**1,765,680.0**	**6,890,055**	**4.03**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	701	202,350	40.1	89.0	57.4	7,355	GAS	1,447,730	1,028,002	1,488,270.0	8,303,122	4.10	5.74
24. BAYSIDE #2	929	194,290	29.0	62.2	45.7	7,390	GAS	1,396,720	1,028,001	1,435,830.0	8,010,564	4.12	5.74
25. BAYSIDE #3	56	1,520	3.8	98.6	90.5	11,474	GAS	16,970	1,027,696	17,440.0	97,328	6.40	5.74
26. BAYSIDE #4	56	1,010	2.5	98.6	90.2	11,386	GAS	11,200	1,026,786	11,500.0	64,235	6.36	5.74
27. BAYSIDE #5	56	3,230	8.0	98.6	91.6	11,102	GAS	34,890	1,027,802	35,860.0	200,104	6.20	5.74
28. BAYSIDE #6	56	2,080	5.2	98.6	90.6	11,168	GAS	22,590	1,028,331	23,230.0	129,560	6.23	5.74
29. BAYSIDE TOTAL	**1,854**	**404,480**	**30.3**	**78.7**	**51.4**	**7,447**	**GAS**	**2,930,100**	**1,027,996**	**3,012,130.0**	**16,804,913**	**4.15**	**5.74**
30. SYSTEM	**4,292**	**1,312,040**	**42.5**	**76.6**	**74.6**	**9,396**	-	-	-	**12,327,590.0**	**50,544,871**	**3.85**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
Document No. 3, Page 20 of 31

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2014

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU) [2]	(L) AS BURNED FUEL COST ($) [1]	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	395	230,310	78.4	81.0	89.7	10,071	COAL	98,970	23,435,789	2,319,440.0	8,038,678	3.49	81.22
2. B.B.#2	395	237,100	80.7	85.9	89.9	10,242	COAL	103,650	23,427,786	2,428,290.0	8,418,808	3.55	81.22
3. B.B.#3	365	220,930	81.4	88.0	89.7	10,495	COAL	98,930	23,436,369	2,318,560.0	8,035,430	3.64	81.22
4. B.B.#4	417	172,000	55.4	60.4	90.9	10,147	COAL	74,470	23,434,940	1,745,200.0	6,048,703	3.52	81.22
B.B. IGNITION	-	-	-	-	-	-	LGT OIL	960	-	5,580.0	131,404	-	136.88
B.B. IGNITION	-	-	-	-	-	-	GAS	15,030	-	15,450.0	96,400	-	6.41
5. B.B. COAL	**1,572**	**860,340**	**73.6**	**78.4**	**90.0**	**10,242**	-	-	-	-	**30,769,423**	**3.58**	-
6. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
7. B.B.C.T.#4 GAS	61	1,240	2.7	-	84.7	10,960	GAS	13,210	1,028,766	13,590.0	84,726	6.83	6.41
8. B.B.C.T.#4 TOTAL	**61**	**1,240**	**2.7**	**99.4**	**84.7**	**10,960**	-	-	-	**13,590.0**	**84,726**	**6.83**	-
9. BIG BEND STATION TOTAL	**1,633**	**861,580**	**70.9**	**79.2**	**90.0**	**10,243**	-	-	-	**8,825,080.0**	**30,854,149**	**3.58**	-
10. POLK #1 GASIFIER	220	155,980	95.3	-	98.7	10,135	COAL	57,340	27,570,108	1,580,870.0	5,030,922	3.23	87.74
11. POLK #1 CT GAS	235	0	0.0	-	0.0	0	GAS	-4,380	0	0.0	28,093	0.00	6.41
12. POLK #1 TOTAL	**220**	**155,980**	**95.3**	**92.8**	**98.7**	**10,135**	-	-	-	**1,580,870.0**	**5,059,015**	**3.24**	-
13. POLK #2 CT GAS	183	8,381	6.2	-	80.3	11,341	GAS	92,460	1,028,012	95,050.0	593,021	7.08	6.41
14. POLK #2 CT OIL	187	169	0.1	-	22.6	10,768	LGT OIL	310	5,870,968	1,820.0	40,799	24.14	131.61
15. POLK #2 TOTAL	**187**	**8,550**	**6.1**	**98.0**	**76.5**	**11,330**	-	-	-	**96,870.0**	**633,820**	**7.41**	-
16. POLK #3 CT GAS	183	5,360	3.9	-	83.7	11,348	GAS	59,170	1,028,055	60,830.0	379,506	7.08	6.41
17. POLK #3 CT OIL	187	170	0.1	-	22.7	10,727	LGT OIL	310	5,870,968	1,820.0	40,800	24.05	131.61
18. POLK #3 TOTAL	**187**	**5,530**	**4.0**	**98.0**	**77.3**	**11,329**	-	-	-	**82,850.0**	**420,306**	**7.60**	-
19. POLK #4 CT GAS	**183**	**2,460**	**1.8**	**98.7**	**96.0**	**10,984**	**GAS**	**26,290**	**1,027,767**	**27,020.0**	**168,619**	**6.85**	**6.41**
20. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
21. POLK STATION TOTAL	**960**	**172,520**	**24.2**	**78.3**	**96.5**	**10,245**	-	-	-	**1,767,410.0**	**6,281,760**	**3.64**	-
22. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
23. BAYSIDE #1	792	113,310	19.2	63.2	46.8	7,352	GAS	810,290	1,028,027	833,000.0	5,197,051	4.59	6.41
24. BAYSIDE #2	1,047	231,630	29.7	88.9	32.7	7,309	GAS	1,646,920	1,027,998	1,693,030.0	10,563,040	4.56	6.41
25. BAYSIDE #3	61	630	1.4	98.6	86.1	10,937	GAS	6,710	1,026,826	6,890.0	43,037	6.83	6.41
26. BAYSIDE #4	61	160	0.4	98.6	87.4	11,188	GAS	1,740	1,028,736	1,790.0	11,160	6.98	6.41
27. BAYSIDE #5	61	710	1.6	98.6	83.1	10,873	GAS	7,500	1,029,333	7,720.0	48,104	6.78	6.41
28. BAYSIDE #6	61	940	2.1	98.6	85.6	10,851	GAS	9,910	1,029,263	10,200.0	63,561	6.76	6.41
29. BAYSIDE TOTAL	**2,083**	**347,380**	**22.4**	**80.2**	**36.5**	**7,348**	**GAS**	**2,483,070**	**1,028,014**	**2,552,630.0**	**15,925,953**	**4.58**	**8.41**
30. SYSTEM	**4,676**	**1,381,480**	**39.7**	**79.5**	**66.1**	**9,515**	-	-	-	**13,145,120.0**	**53,061,862**	**3.84**	-

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition oil/gas.
[2] Fuel burned (MM BTU) system total excludes ignition oil/gas.
[3] City of Tampa on long term reserve standby.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
	HEAVY OIL						
1.	PURCHASES:						
2.	UNITS (BBL)	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0
5.	BURNED:						
6.	UNITS (BBL)	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0
9.	ENDING INVENTORY:						
10.	UNITS (BBL)	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0
	LIGHT OIL						
14.	PURCHASES:						
15.	UNITS (BBL)	3,360	5,340	4,410	3,020	3,120	2,630
16.	UNIT COST ($/BBL)	140.75	140.85	140.60	140.04	139.57	139.08
17.	AMOUNT ($)	472,915	752,116	620,058	422,931	435,464	365,784
18.	BURNED:						
19.	UNITS (BBL)	3,360	5,340	4,410	3,020	3,120	2,630
20.	UNIT COST ($/BBL)	24.07	20.09	23.13	16.31	15.94	40.28
21.	AMOUNT ($)	80,865	107,291	102,000	49,256	49,743	105,938
22.	ENDING INVENTORY:						
23.	UNITS (BBL)	91,441	91,441	91,441	91,441	91,441	91,441
24.	UNIT COST ($/BBL)	132.71	133.06	133.33	133.48	133.61	133.73
25.	AMOUNT ($)	12,134,847	12,167,092	12,191,830	12,205,227	12,217,409	12,228,038
26.	DAYS SUPPLY: NORMAL	538	545	561	573	564	574
27.	DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13
	COAL						
28.	PURCHASES:						
29.	UNITS (TONS)	466,600	376,600	361,600	431,600	426,600	446,600
30.	UNIT COST ($/TON)	78.48	77.42	77.20	77.80	77.86	79.00
31.	AMOUNT ($)	36,619,875	29,154,812	27,916,217	33,580,595	33,215,556	35,280,102
32.	BURNED:						
33.	UNITS (TONS)	469,920	335,860	390,690	352,470	396,480	466,490
34.	UNIT COST ($/TON)	80.95	81.57	79.88	80.13	79.86	78.96
35.	AMOUNT ($)	38,040,790	27,394,532	31,207,087	28,242,538	31,661,806	36,835,660
36.	ENDING INVENTORY:						
37.	UNITS (TONS)	555,960	596,700	567,610	646,740	676,860	656,970
38.	UNIT COST ($/TON)	80.69	79.36	78.79	78.16	77.79	78.39
39.	AMOUNT ($)	44,860,231	47,356,658	44,722,675	50,547,776	52,655,325	51,500,881
40.	DAYS SUPPLY:	42	49	46	48	46	42
	NATURAL GAS						
41.	PURCHASES:						
42.	UNITS (MCF)	2,427,330	3,319,240	3,238,340	3,926,100	5,435,461	5,256,930
43.	UNIT COST ($/MCF)	6.32	5.73	5.82	5.85	5.58	5.64
44.	AMOUNT ($)	15,334,418	19,019,165	18,849,845	22,973,304	30,305,550	29,652,568
45.	BURNED:						
46.	UNITS (MCF)	2,427,330	3,319,240	3,238,340	3,926,100	5,192,270	5,256,930
47.	UNIT COST ($/MCF)	6.55	5.73	5.83	5.86	5.65	5.63
48.	AMOUNT ($)	15,904,418	19,016,765	18,874,145	23,010,504	29,320,658	29,594,838
49.	ENDING INVENTORY:						
50.	UNITS (MCF)	729,572	729,572	729,572	729,572	972,762	972,762
51.	UNIT COST ($/MCF)	3.81	3.81	3.78	3.72	3.75	3.78
52.	AMOUNT ($)	2,776,500	2,778,900	2,754,600	2,717,400	3,645,600	3,678,200
53.	DAYS SUPPLY:	5	5	5	5	7	7
	NUCLEAR						
54.	BURNED:						
55.	UNITS (MMBTU)	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0
	OTHER						
58.	PURCHASES:						
59.	UNITS (MMBTU)	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0
62.	BURNED:						
63.	UNITS (MMBTU)	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0
66.	ENDING INVENTORY:						
67.	UNITS (MMBTU)	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	0	0	0	0	0	0	0
3.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	AMOUNT ($)	0	0	0	0	0	0	0
5.	BURNED:							
6.	UNITS (BBL)	0	0	0	0	0	0	0
7.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	AMOUNT ($)	0	0	0	0	0	0	0
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	0	0	0	0	0	0	0
11.	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	AMOUNT ($)	0	0	0	0	0	0	0
13.	DAYS SUPPLY:	0	0	0	0	0	0	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	3,500	2,450	3,580	1,560	4,300	1,580	38,850
16.	UNIT COST ($/BBL)	138.83	138.65	138.40	138.14	137.83	137.47	139.40
17.	AMOUNT ($)	485,909	339,701	495,486	215,491	592,682	217,207	5,415,744
18.	BURNED:							
19.	UNITS (BBL)	3,500	2,450	3,580	1,560	4,300	1,580	38,850
20.	UNIT COST ($/BBL)	28.48	32.14	31.84	50.56	21.33	51.64	26.76
21.	AMOUNT ($)	99,673	78,747	113,976	78,870	91,700	81,599	1,039,658
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	91,441	91,441	91,441	91,441	91,441	91,441	91,441
24.	UNIT COST ($/BBL)	133.86	133.95	134.06	134.11	134.19	134.24	134.24
25.	AMOUNT ($)	12,240,053	12,248,190	12,258,180	12,263,484	12,270,841	12,275,046	12,275,046
26.	DAYS SUPPLY: NORMAL	576	582	591	591	572	599	-
27.	DAYS SUPPLY: EMERGENCY	13	13	13	13	13	13	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	446,600	521,600	376,600	356,600	371,600	410,400	4,993,000
30.	UNIT COST ($/TON)	82.39	82.23	82.27	82.51	82.41	82.43	80.17
31.	AMOUNT ($)	36,795,271	42,891,858	30,984,676	29,423,753	30,623,085	33,827,920	400,313,720
32.	BURNED:							
33.	UNITS (TONS)	482,940	478,770	372,780	376,770	366,520	433,360	4,923,050
34.	UNIT COST ($/TON)	80.53	81.29	82.59	82.29	83.67	82.61	81.14
35.	AMOUNT ($)	38,892,495	38,919,999	30,786,167	31,006,213	30,667,179	35,800,345	399,454,811
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	620,630	663,460	667,280	647,110	652,190	629,230	629,230
38.	UNIT COST ($/TON)	80.51	81.91	82.53	83.09	83.52	83.99	83.99
39.	AMOUNT ($)	49,967,180	54,343,956	55,067,945	53,768,473	54,472,931	52,851,873	52,851,873
40.	DAYS SUPPLY:	43	50	54	51	50	45	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	5,488,140	5,299,620	6,372,950	5,167,110	3,221,189	2,693,610	51,846,020
43.	UNIT COST ($/MCF)	5.64	5.70	5.43	5.61	5.90	6.46	5.73
44.	AMOUNT ($)	30,963,378	30,198,894	34,591,098	29,007,927	18,995,303	17,404,718	297,296,168
45.	BURNED:							
46.	UNITS (MCF)	5,488,140	5,299,620	6,372,950	5,167,110	3,464,380	2,693,610	51,846,020
47.	UNIT COST ($/MCF)	5.63	5.69	5.42	5.60	5.71	6.38	5.73
48.	AMOUNT ($)	30,901,943	30,153,961	34,562,106	28,957,822	19,785,992	17,179,918	297,263,070
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	972,762	972,762	972,762	972,762	729,572	729,572	729,572
51.	UNIT COST ($/MCF)	3.82	3.83	3.83	3.86	3.94	4.12	4.12
52.	AMOUNT ($)	3,711,400	3,727,800	3,729,600	3,751,600	2,877,750	3,006,150	3,006,150
53.	DAYS SUPPLY:	7	7	7	7	5	5	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E6

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jan-14	SEMINOLE	JURISD. SCH. - D	800.0	0.0	800.0	3.148	3.325	25,180.00	26,597.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	17,580.0	0.0	17,580.0	3.238	3.563	569,297.61	626,290.00	56,992.39
	TOTAL		**18,380.0**	**0.0**	**18,380.0**	**3.234**	**3.552**	**594,477.61**	**652,887.00**	**58,409.39**
Feb-14	SEMINOLE	JURISD. SCH. - D	680.0	0.0	680.0	3.037	3.245	20,650.00	22,067.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	15,930.0	0.0	15,930.0	3.039	3.344	484,187.94	532,660.00	48,472.06
	TOTAL		**16,610.0**	**0.0**	**16,610.0**	**3.039**	**3.340**	**504,837.94**	**554,727.00**	**49,889.06**
Mar-14	SEMINOLE	JURISD. SCH. - D	880.0	0.0	880.0	2.972	3.133	26,150.00	27,567.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	19,700.0	0.0	19,700.0	2.999	3.300	590,895.45	650,050.00	59,154.55
	TOTAL		**20,580.0**	**0.0**	**20,580.0**	**2.998**	**3.293**	**617,045.45**	**677,617.00**	**60,571.55**
Apr-14	SEMINOLE	JURISD. SCH. - D	1,080.0	0.0	1,080.0	3.134	3.265	33,850.00	35,267.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	17,660.0	0.0	17,660.0	3.304	3.635	583,559.82	641,980.00	58,420.18
	TOTAL		**18,740.0**	**0.0**	**18,740.0**	**3.295**	**3.614**	**617,409.82**	**677,247.00**	**59,837.18**
May-14	SEMINOLE	JURISD. SCH. - D	920.0	0.0	920.0	3.027	3.181	27,850.00	29,267.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	10,050.0	0.0	10,050.0	3.335	3.669	335,166.48	368,720.00	33,553.52
	TOTAL		**10,970.0**	**0.0**	**10,970.0**	**3.309**	**3.628**	**363,016.48**	**397,987.00**	**34,970.52**
Jun-14	SEMINOLE	JURISD. SCH. - D	990.0	0.0	990.0	3.161	3.304	31,290.00	32,707.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	10,080.0	0.0	10,080.0	3.581	3.939	360,927.54	397,060.00	36,132.46
	TOTAL		**11,070.0**	**0.0**	**11,070.0**	**3.543**	**3.882**	**392,217.54**	**429,767.00**	**37,549.46**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON SALES
Jul-14	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	3.198	3.338	32,300.00	33,717.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	8,300.0	0.0	8,300.0	3.699	4.069	307,014.75	337,750.00	30,735.25
	TOTAL		**9,310.0**	**0.0**	**9,310.0**	**3.645**	**3.990**	**339,314.75**	**371,467.00**	**32,152.25**
Aug-14	SEMINOLE	JURISD. SCH. - D	990.0	0.0	990.0	3.449	3.593	34,150.00	35,567.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	7,710.0	0.0	7,710.0	4.175	4.593	321,895.08	354,120.00	32,224.92
	TOTAL		**8,700.0**	**0.0**	**8,700.0**	**4.092**	**4.479**	**356,045.08**	**389,687.00**	**33,641.92**
Sep-14	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	3.303	3.443	33,360.00	34,777.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	8,240.0	0.0	8,240.0	3.923	4.316	323,258.58	355,620.00	32,361.42
	TOTAL		**9,250.0**	**0.0**	**9,250.0**	**3.855**	**4.221**	**356,618.58**	**390,397.00**	**33,778.42**
Oct-14	SEMINOLE	JURISD. SCH. - D	730.0	0.0	730.0	3.279	3.474	23,940.00	25,357.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	10,160.0	0.0	10,160.0	3.528	3.881	358,473.24	394,360.00	35,886.76
	TOTAL		**10,890.0**	**0.0**	**10,890.0**	**3.512**	**3.854**	**382,413.24**	**419,717.00**	**37,303.76**
Nov-14	SEMINOLE	JURISD. SCH. - D	650.0	0.0	650.0	3.169	3.387	20,600.00	22,017.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	9,600.0	0.0	9,600.0	3.355	3.691	322,113.24	354,360.00	32,246.76
	TOTAL		**10,250.0**	**0.0**	**10,250.0**	**3.344**	**3.672**	**342,713.24**	**376,377.00**	**33,663.76**
Dec-14	SEMINOLE	JURISD. SCH. - D	580.0	0.0	580.0	3.217	3.462	18,660.00	20,077.00	1,417.00
	VARIOUS	JURISD. MKT. BASE	15,000.0	0.0	15,000.0	3.312	3.643	496,732.14	546,460.00	49,727.86
	TOTAL		**15,580.0**	**0.0**	**15,580.0**	**3.308**	**3.636**	**515,392.14**	**566,537.00**	**51,144.86**
TOTAL	SEMINOLE	JURISD. SCH. - D	10,320.0	0.0	10,320.0	3.178	3.343	327,980.00	344,984.00	17,004.00
	VARIOUS	JURISD. MKT. BASE	150,010.0	0.0	150,010.0	3.369	3.706	5,053,521.87	5,559,430.00	505,908.13
	TOTAL		**160,330.0**	**0.0**	**160,330.0**	**3.357**	**3.683**	**5,381,501.87**	**5,904,414.00**	**522,912.13**

Docket No. 130001-EI
Exhibit No.____ (PAR-3)
Document No. 3, Page 25 of 31

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH JUNE 2014

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jan-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	2,320.0	0.0	0.0	2,320.0	3.849	3.849	89,300.00
	TOTAL		**2,320.0**	**0.0**	**0.0**	**2,320.0**	**3.849**	**3.849**	**89,300.00**
Feb-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	3,830.0	0.0	0.0	3,830.0	3.791	3.791	145,200.00
	TOTAL		**3,830.0**	**0.0**	**0.0**	**3,830.0**	**3.791**	**3.791**	**145,200.00**
Mar-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	300.0	0.0	0.0	300.0	7.810	7.810	23,430.00
	PASCO COGEN	SCH. - D	7,940.0	0.0	0.0	7,940.0	3.718	3.718	295,190.00
	TOTAL		**8,240.0**	**0.0**	**0.0**	**8,240.0**	**3.867**	**3.867**	**318,620.00**
Apr-14									
	OLEANDER	SCH. - D	780.0	0.0	0.0	780.0	7.060	7.060	55,070.00
	CALPINE	SCH. - D	350.0	0.0	0.0	350.0	6.094	6.094	21,330.00
	PASCO COGEN	SCH. - D	9,590.0	0.0	0.0	9,590.0	3.850	3.850	369,200.00
	TOTAL		**10,720.0**	**0.0**	**0.0**	**10,720.0**	**4.157**	**4.157**	**445,600.00**
May-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	17,940.0	0.0	0.0	17,940.0	3.865	3.865	693,330.00
	TOTAL		**17,940.0**	**0.0**	**0.0**	**17,940.0**	**3.865**	**3.865**	**693,330.00**
Jun-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	1,290.0	0.0	0.0	1,290.0	6.836	6.836	88,190.00
	PASCO COGEN	SCH. - D	16,730.0	0.0	0.0	16,730.0	3.881	3.881	649,250.00
	TOTAL		**18,020.0**	**0.0**	**0.0**	**18,020.0**	**4.092**	**4.092**	**737,440.00**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JULY 2014 THROUGH DECEMBER 2014

SCHEDULE E7

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jul-14									
	OLEANDER	SCH. - D	3,530.0	0.0	0.0	3,530.0	6.465	6.465	228,230.00
	CALPINE	SCH. - D	3,370.0	0.0	0.0	3,370.0	6.432	6.432	216,750.00
	PASCO COGEN	SCH. - D	16,880.0	0.0	0.0	16,880.0	3.928	3.928	663,020.00
	TOTAL		**23,780.0**	**0.0**	**0.0**	**23,780.0**	**4.659**	**4.659**	**1,108,000.00**
Aug-14									
	OLEANDER	SCH. - D	7,640.0	0.0	0.0	7,640.0	6.603	6.603	504,480.00
	CALPINE	SCH. - D	5,580.0	0.0	0.0	5,580.0	6.716	6.716	374,760.00
	PASCO COGEN	SCH. - D	19,100.0	0.0	0.0	19,100.0	3.922	3.922	749,170.00
	TOTAL		**32,320.0**	**0.0**	**0.0**	**32,320.0**	**5.038**	**5.038**	**1,628,410.00**
Sep-14									
	OLEANDER	SCH. - D	3,880.0	0.0	0.0	3,880.0	6.006	6.006	233,030.00
	CALPINE	SCH. - D	4,200.0	0.0	0.0	4,200.0	6.635	6.635	278,680.00
	PASCO COGEN	SCH. - D	23,340.0	0.0	0.0	23,340.0	3.917	3.917	914,260.00
	TOTAL		**31,420.0**	**0.0**	**0.0**	**31,420.0**	**4.538**	**4.538**	**1,425,970.00**
Oct-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	540.0	0.0	0.0	540.0	6.931	6.931	37,430.00
	PASCO COGEN	SCH. - D	15,690.0	0.0	0.0	15,690.0	3.928	3.928	616,260.00
	TOTAL		**16,230.0**	**0.0**	**0.0**	**16,230.0**	**4.028**	**4.028**	**653,690.00**
Nov-14									
	OLEANDER	SCH. - D	1,510.0	0.0	0.0	1,510.0	5.902	5.902	89,120.00
	CALPINE	SCH. - D	550.0	0.0	0.0	550.0	5.718	5.718	31,450.00
	PASCO COGEN	SCH. - D	14,170.0	0.0	0.0	14,170.0	3.876	3.876	549,290.00
	TOTAL		**16,230.0**	**0.0**	**0.0**	**16,230.0**	**4.127**	**4.127**	**669,860.00**
Dec-14									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	1,660.0	0.0	0.0	1,660.0	4.115	4.115	68,310.00
	TOTAL		**1,660.0**	**0.0**	**0.0**	**1,660.0**	**4.115**	**4.115**	**68,310.00**
TOTAL Jan-14 THRU Dec-14	OLEANDER	SCH. - D	17,340.0	0.0	0.0	17,340.0	6.401	6.401	1,109,930.00
	CALPINE	SCH. - D	16,180.0	0.0	0.0	16,180.0	6.626	6.626	1,072,020.00
	PASCO COGEN	SCH. - D	149,190.0	0.0	0.0	149,190.0	3.889	3.889	5,801,780.00
	TOTAL		**182,710.0**	**0.0**	**0.0**	**182,710.0**	**4.370**	**4.370**	**7,983,730.00**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E8

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUST-MENT
Jan-14	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.300	3.300	188,120.00
		AS AVAIL.	16,230.0	0.0	0.0	16,230.0	3.274	3.274	531,400.00
	TOTAL		21,930.0	0.0	0.0	21,930.0	3.281	3.281	719,520.00
Feb-14	VARIOUS	CO-GEN.							
		FIRM	5,150.0	0.0	0.0	5,150.0	3.261	3.261	167,960.00
		AS AVAIL.	16,140.0	0.0	0.0	16,140.0	2.605	2.605	420,380.00
	TOTAL		21,290.0	0.0	0.0	21,290.0	2.763	2.763	588,340.00
Mar-14	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.246	3.246	185,040.00
		AS AVAIL.	16,190.0	0.0	0.0	16,190.0	3.835	3.835	620,910.00
	TOTAL		21,890.0	0.0	0.0	21,890.0	3.682	3.682	805,950.00
Apr-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.230	3.230	200,580.00
		AS AVAIL.	16,080.0	0.0	0.0	16,080.0	2.935	2.935	471,920.00
	TOTAL		22,290.0	0.0	0.0	22,290.0	3.017	3.017	672,500.00
May-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.222	3.222	206,880.00
		AS AVAIL.	16,180.0	0.0	0.0	16,180.0	3.243	3.243	524,770.00
	TOTAL		22,600.0	0.0	0.0	22,600.0	3.237	3.237	731,650.00
Jun-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.218	3.218	199,840.00
		AS AVAIL.	16,100.0	0.0	0.0	16,100.0	3.132	3.132	504,310.00
	TOTAL		22,310.0	0.0	0.0	22,310.0	3.156	3.156	704,150.00
Jul-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.279	3.279	210,540.00
		AS AVAIL.	16,220.0	0.0	0.0	16,220.0	3.293	3.293	534,110.00
	TOTAL		22,640.0	0.0	0.0	22,640.0	3.289	3.289	744,650.00
Aug-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.327	3.327	213,620.00
		AS AVAIL.	16,080.0	0.0	0.0	16,080.0	3.440	3.440	553,120.00
	TOTAL		22,500.0	0.0	0.0	22,500.0	3.408	3.408	766,740.00
Sep-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.358	3.358	208,530.00
		AS AVAIL.	16,180.0	0.0	0.0	16,180.0	2.911	2.911	470,930.00
	TOTAL		22,390.0	0.0	0.0	22,390.0	3.035	3.035	679,460.00
Oct-14	VARIOUS	CO-GEN.							
		FIRM	6,420.0	0.0	0.0	6,420.0	3.373	3.373	216,570.00
		AS AVAIL.	16,260.0	0.0	0.0	16,260.0	3.099	3.099	503,840.00
	TOTAL		22,680.0	0.0	0.0	22,680.0	3.176	3.176	720,410.00
Nov-14	VARIOUS	CO-GEN.							
		FIRM	6,210.0	0.0	0.0	6,210.0	3.393	3.393	210,710.00
		AS AVAIL.	16,020.0	0.0	0.0	16,020.0	3.174	3.174	508,460.00
	TOTAL		22,230.0	0.0	0.0	22,230.0	3.235	3.235	719,170.00
Dec-14	VARIOUS	CO-GEN.							
		FIRM	5,700.0	0.0	0.0	5,700.0	3.395	3.395	193,540.00
		AS AVAIL.	16,150.0	0.0	0.0	16,150.0	1.873	1.873	302,480.00
	TOTAL		21,850.0	0.0	0.0	21,850.0	2.270	2.270	496,020.00
TOTAL Jan-14 THRU Dec-14	VARIOUS	CO-GEN.							
		FIRM	72,770.0	0.0	0.0	72,770.0	3.301	3.301	2,401,930.00
		AS AVAIL.	193,830.0	0.0	0.0	193,830.0	3.068	3.068	5,946,630.00
	TOTAL		266,600.0	0.0	0.0	266,600.0	3.131	3.131	8,348,560.00

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2014 THROUGH DECEMBER 2014

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		(10)
								COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (9B)-(8)
Jan-14	VARIOUS	ECONOMY	27,960.0	0.0	27,960.0	4.000	1,118,480.00	4.562	1,275,406.73	156,926.73
Feb-14	VARIOUS	ECONOMY	27,690.0	0.0	27,690.0	4.000	1,107,530.00	4.561	1,262,941.34	155,411.34
Mar-14	VARIOUS	ECONOMY	37,410.0	0.0	37,410.0	4.000	1,496,400.00	4.561	1,706,365.27	209,965.27
Apr-14	VARIOUS	ECONOMY	35,130.0	0.0	35,130.0	4.000	1,405,270.00	4.561	1,602,438.67	197,168.67
May-14	VARIOUS	ECONOMY	46,100.0	0.0	46,100.0	4.000	1,843,860.00	4.561	2,102,598.28	258,738.28
Jun-14	VARIOUS	ECONOMY	46,630.0	0.0	46,630.0	4.000	1,865,250.00	4.561	2,126,962.93	261,712.93
Jul-14	VARIOUS	ECONOMY	58,190.0	0.0	58,190.0	4.326	2,517,540.00	4.830	2,810,739.30	293,199.30
Aug-14	VARIOUS	ECONOMY	45,370.0	0.0	45,370.0	4.336	1,967,230.00	4.838	2,194,987.04	227,757.04
Sep-14	VARIOUS	ECONOMY	56,590.0	0.0	56,590.0	4.311	2,439,700.00	4.818	2,726,332.62	286,632.62
Oct-14	VARIOUS	ECONOMY	48,550.0	0.0	48,550.0	4.000	1,942,060.00	4.561	2,214,549.01	272,489.01
Nov-14	VARIOUS	ECONOMY	32,710.0	0.0	32,710.0	4.000	1,308,440.00	4.561	1,492,026.32	183,586.32
Dec-14	VARIOUS	ECONOMY	33,520.0	0.0	33,520.0	4.000	1,340,720.00	4.561	1,528,852.48	188,132.48
TOTAL	VARIOUS	ECONOMY	495,850.0	0.0	495,850.0	4.105	20,352,480.00	4.647	23,044,200.00	2,691,720.00

Docket No. 130001-EI
Exhibit No.____ (PAR-3)
Document No. 3, Page 29 of 31

SCHEDULE E10
REVISED 9/16/13

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current Jan 13 - Oct 13	Approved Nov 13 - Dec 13	Difference $	Difference %	Projected Jan 14 - Dec 14	Difference $	Difference %
Base Rate Revenue *	55.45	60.98	5.53	10.0%	60.98	0.00	0.0%
Fuel Recovery Revenue	33.69	33.69	0.00	0.0%	36.09	2.40	7.1%
Conservation Revenue	2.98	2.98	0.00	0.0%	2.95	(0.03)	-1.0%
Capacity Revenue	2.32	2.32	0.00	0.0%	2.02	(0.30)	-12.9%
Environmental Revenue	5.58	5.58	0.00	0.0%	4.83	(0.75)	-13.4%
Florida Gross Receipts Tax Revenue	2.56	2.71	0.15	5.9%	2.74	0.03	1.1%
TOTAL REVENUE	**$102.58**	**$108.26**	**$5.68**	**5.5%**	**$109.61**	**$1.35**	**1.2%**

*** Reflects base rate settlement approved on 9/11/13 in Docket No. 130040-EI. Base rates effective November 1, 2013.**

Docket No. 130001-EI
Exhibit No. ____ (PAR-3)
Document No. 3, Page 30 of 31
REVISED: 9/16/2013

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2011	ACTUAL 2012	ACT/EST 2013	EST 2014	DIFFERENCE (%) 2012-2011	2013-2012	2014-2013
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
2 LIGHT OIL [1]	2,915,586	4,902,843	3,662,424	1,039,658	68.2%	-25.3%	-71.6%
3 COAL	386,430,361	395,142,292	383,830,271	399,454,811	2.3%	-2.9%	4.1%
4 NATURAL GAS	348,457,572	305,701,892	314,247,742	297,263,070	-12.3%	2.8%	-5.4%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**737,803,519**	**705,747,027**	**701,740,437**	**697,757,539**	**-4.3%**	**-0.6%**	**-0.6%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
9 LIGHT OIL [1]	13,423	20,242	10,553	4,233	50.8%	-47.9%	-59.9%
10 COAL	10,888,182	10,690,533	10,940,725	11,544,670	-1.8%	2.3%	5.5%
11 NATURAL GAS	7,392,465	7,567,891	7,550,325	6,973,999	2.4%	-0.2%	-7.6%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**18,294,070**	**18,278,666**	**18,501,603**	**18,522,902**	**-0.1%**	**1.2%**	**0.1%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	0	0	0	0	0.0%	0.0%	0.0%
16 LIGHT OIL (BBL) [1]	27,473	40,791	52,693	38,850	48.5%	29.2%	-26.3%
17 COAL (TON)	4,763,638	4,671,399	4,729,963	4,923,050	-1.9%	1.3%	4.1%
18 NATURAL GAS (MCF)	55,514,960	56,591,885	56,474,119	51,846,020	1.9%	-0.2%	-8.2%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
22 LIGHT OIL [1]	146,019	208,086	167,608	45,510	42.5%	-19.5%	-72.8%
23 COAL	114,391,211	112,307,550	113,314,456	118,029,000	-1.8%	0.9%	4.2%
24 NATURAL GAS	56,296,514	57,395,050	57,620,198	53,170,540	2.0%	0.4%	-7.7%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**170,833,745**	**169,910,686**	**171,102,262**	**171,245,050**	**-0.6%**	**0.7%**	**0.1%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
29 LIGHT OIL [1]	0.07	0.11	0.06	0.02	57.1%	-45.5%	-66.7%
30 COAL	59.52	58.49	59.13	62.33	-1.7%	1.1%	5.4%
31 NATURAL GAS	40.41	41.40	40.81	37.85	2.4%	-1.4%	-7.7%
32 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**0.0%**	**0.0%**	**0.0%**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
36 LIGHT OIL ($/BBL) [1]	106.13	120.19	69.50	26.76	13.2%	-42.2%	-61.5%
37 COAL ($/TON)	81.12	84.59	81.15	81.14	4.3%	-4.1%	0.0%
38 NATURAL GAS ($/MCF)	6.28	5.40	5.56	5.73	-14.0%	3.0%	3.1%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
42 LIGHT OIL [1]	19.97	23.56	21.85	22.84	18.0%	-7.3%	4.5%
43 COAL	3.38	3.52	3.39	3.38	4.1%	-3.7%	-0.3%
44 NATURAL GAS	6.19	5.33	5.45	5.59	-13.9%	2.3%	2.6%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**4.32**	**4.16**	**4.10**	**4.07**	**-3.9%**	**-1.2%**	**-0.7%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	0	0	0	0	0.0%	0.0%	0.0%
49 LIGHT OIL [1]	10,878	10,280	15,883	10,751	-5.5%	54.5%	-32.3%
50 COAL	10,506	10,505	10,357	10,224	0.0%	-1.4%	-1.3%
51 NATURAL GAS	7,615	7,584	7,631	7,624	-0.4%	0.6%	-0.1%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	9,338	9,296	9,248	9,245	-0.4%	-0.5%	0.0%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
56 LIGHT OIL [1]	21.72	24.22	34.71	24.56	11.5%	43.3%	-29.2%
57 COAL	3.55	3.70	3.51	3.46	4.2%	-5.1%	-1.4%
58 NATURAL GAS	4.71	4.04	4.16	4.26	-14.2%	3.0%	2.4%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	4.03	3.86	3.79	3.77	-4.2%	-1.8%	-0.5%

[1] DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

LEVELIZED AND TIERED FUEL RATE

JANUARY 2014 - DECEMBER 2014

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2014 through December 2014
REVISED 9/16/13

	Annual Units MWH	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues $	Tiered Fuel Rates Cents/kWh	Annual Fuel Revenues $
Residential Excluding TOU:					
TIER I (Up to 1,000) kWh	5,962,033	3.910	233,115,495	3.609	215,169,775
TIER II (Over 1,000) kWh	2,567,342	3.910	100,383,067	4.609	118,328,787
Total	8,529,375		333,498,562		333,498,562

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 5

POLK UNIT 1 IGNITION OIL CONVERSION

JANUARY 2014 - DECEMBER 2014

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2014 THROUGH DECEMBER 2014
REVISED 9/16/13

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062
2	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062
5														
6														
7	AVERAGE BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	257,134	3,085,612
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	1,542,806	1,799,941	2,057,075	2,314,209	2,571,344	2,828,478	3,085,612	3,342,747	3,599,881	3,857,015	4,114,150	4,371,284	1,542,806
12	ENDING BALANCE DEPRECIATION	1,799,941	2,057,075	2,314,209	2,571,344	2,828,478	3,085,612	3,342,747	3,599,881	3,857,015	4,114,150	4,371,284	4,628,418	4,628,418
13														
14														
15	ENDING NET INVESTMENT	13,628,121	13,370,987	13,113,852	12,856,718	12,599,584	12,342,449	12,085,315	11,828,181	11,571,046	11,313,912	11,056,778	10,799,643	10,799,643
16														
17														
18	AVERAGE INVESTMENT	$ 13,756,688	$ 13,499,554	$ 13,242,420	$ 12,985,285	$ 12,728,151	$ 12,471,017	$ 12,213,882	$ 11,956,748	$ 11,699,613	$ 11,442,479	$ 11,185,345	$ 10,928,210	
19	ALLOWED EQUITY RETURN	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	.368839%	
20	EQUITY COMPONENT AFTER-TAX	50,740	49,792	48,843	47,895	46,946	45,998	45,050	44,101	43,153	42,204	41,256	40,308	546,286
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	82,818	81,271	79,722	78,174	76,625	75,078	73,531	71,982	70,434	68,885	67,338	65,791	891,649
23														
24	ALLOWED DEBT RETURN	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	.184178%	
25	DEBT COMPONENT	$ 25,337	$ 24,863	$ 24,390	$ 23,916	$ 23,442	$ 22,969	22,495	22,022	21,548	21,075	20,601	20,127	272,785
26														
27	TOTAL RETURN REQUIREMENTS	$ 108,155	$ 106,134	$ 104,112	$ 102,090	$ 100,067	$ 98,047	96,026	94,004	91,982	89,960	87,939	85,918	1,164,434
28														
29	TOTAL DEPRECIATION & RETURN	$ 365,289	$ 363,268	$ 361,246	$ 359,224	$ 357,201	$ 355,181	353,160	351,138	349,116	347,094	345,073	343,052	4,250,042
30														
31	ESTIMATED FUEL SAVINGS	$467,544	$429,570	$610,456	$749,244	$688,170	$736,400	$488,114	$0	$0	$679,695	$1,299,753	$0	$6,148,946
32	TOTAL DEPRECIATION & RETURN	$365,289	$363,268	$361,246	$359,224	$357,201	$355,181	$353,160	$351,138	$349,116	$347,094	$345,073	$343,052	4,250,042
33	NET BENEFIT (COST) TO RATEPAYER	$102,255	$66,302	$249,210	$390,020	$330,969	$381,219	$134,954	($351,138)	($349,116)	$332,601	$954,680	($343,052)	$1,898,904

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9.4343% (EQUITY 7.2242% , DEBT 2.2101%)
36 THE RATES ARE FROM THE APPROVED 9/11/2013 BASE RATE SETTLEMENT
37
38 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
GPIF 2012 FINAL TRUE-UP

GENERATING PERFORMANCE INCENTIVE FACTOR

INDEX

DOCUMENT NO.	TITLE	BATES STAMPED PAGE NO.
1	GPIF Schedules	10
2	Actual Unit Performance Data	43

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 49
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Brian S. Buckley - BSB-1

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
GPIF 2012 FINAL TRUE-UP
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 130001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2012 - DECEMBER 2012

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2012 - DECEMBER 2012
TRUE-UP
TABLE OF CONTENTS

SCHEDULE	PAGE
GPIF REWARD / PENALTY TABLE - ACTUAL	2
GPIF CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS	3
CALCULATIONS OF SYSTEM GPIF POINTS - ACTUAL	4
GPIF TARGET AND RANGE SUMMARY	5
UNIT PERFORMANCE DATA - ACTUAL	6
ADJUSTMENTS TO PERFORMANCE	7 - 13
ADJUSTMENTS TO HEAT RATE	14 - 20
PLANNED OUTAGE SCHEDULE - ACTUAL	21
CRITICAL PATH METHOD DIAGRAMS	22 - 23
GENERATING PERFORMANCE INCENTIVE POINTS TABLES	24 - 30
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE	31
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION	32

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2012 - DECEMBER 2012

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,723.5	7,780.7
+9	26,751.2	7,002.7
+8	23,778.8	6,224.6
+7	20,806.5	5,446.5
+6	17,834.1	4,668.4
+5	14,861.8	3,890.4
+4	11,889.4	3,112.3
+3	8,917.1	2,334.2
+2	5,944.7	1,556.1
+1	2,972.4	778.1
0	0.0	0.0
-1	(2,880.4)	(778.1)
-2	(5,760.8)	(1,556.1)
-3	(8,641.1)	(2,334.2)
-4	(11,521.5)	(3,112.3)
-5	(14,401.9)	(3,890.4)
-6	(17,282.3)	(4,668.4)
-7	(20,162.7)	(5,446.5)
-8	(23,043.0)	(6,224.6)
-9	(25,923.4)	(7,002.7)
-10	(28,803.8)	(7,780.7)

GPI POINTS -1.513

PENALTY DOLLARS ($1,177,059)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2012 - DECEMBER 2012

Line 1	Beginning of period balance of common equity: End of month common equity:		$ 1,878,993,511
Line 2	Month of January	2012	$ 1,890,121,442
Line 3	Month of February	2012	$ 1,852,302,024
Line 4	Month of March	2012	$ 1,864,867,823
Line 5	Month of April	2012	$ 1,876,338,327
Line 6	Month of May	2012	$ 1,866,350,234
Line 7	Month of June	2012	$ 1,885,460,709
Line 8	Month of July	2012	$ 1,911,774,155
Line 9	Month of August	2012	$ 1,937,479,453
Line 10	Month of September	2012	$ 1,958,448,602
Line 11	Month of October	2012	$ 1,904,697,463
Line 12	Month of November	2012	$ 1,977,729,852
Line 13	Month of December	2012	$ 1,986,053,783
Line 14	(Summation of line 1 through line 13 divided by 13)		$ 1,906,970,568
Line 15	25 Basis points		0.0025
Line 16	Revenue Expansion Factor		61.17%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$ 7,794,243
Line 18	Jurisdictional Sales		18,408,581 MWH
Line 19	Total Sales		18,440,546 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		99.83%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$ 7,780,732**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2012 - DECEMBER 2012

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	67.8%	EAF	0.30%	-10.000	-0.030
BIG BEND 2	76.7%	EAF	5.09%	1.326	0.067
BIG BEND 3	69.3%	EAF	9.20%	-10.000	-0.920
BIG BEND 4	76.9%	EAF	6.50%	-0.720	-0.047
POLK 1	71.5%	EAF	0.81%	-10.000	-0.081
BAYSIDE 1	94.7%	EAF	1.35%	-0.730	-0.010
BAYSIDE 2	80.3%	EAF	0.95%	2.387	0.023
BIG BEND 1	10467	ANOHR	19.20%	0.000	0.000
BIG BEND 2	10356	ANOHR	12.41%	-0.272	-0.034
BIG BEND 3	10595	ANOHR	12.03%	0.000	0.000
BIG BEND 4	10420	ANOHR	11.77%	1.695	0.200
POLK 1	10619	ANOHR	6.81%	-10.000	-0.681
BAYSIDE 1	7206	ANOHR	6.86%	0.000	0.000
BAYSIDE 2	7286	ANOHR	6.73%	0.000	0.000
			100.00%		-1.513

GPIF REWARD	**$ (1,177,059)**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF MAX. (%)	RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	0.30%	81.87	84.6	76.3	89.3	(936.3)	67.8%	(936.3)
BIG BEND 2	5.09%	76.18	80.1	68.4	1,512.2	(122.3)	76.7%	16.2
BIG BEND 3	9.20%	79.98	83.0	73.9	2,734.4	(1,685.0)	69.3%	(1,685.0)
BIG BEND 4	6.50%	77.41	80.9	70.3	1,932.3	(1,553.3)	76.9%	(111.9)
POLK 1	0.81%	85.50	86.8	83.0	241.1	(84.9)	71.5%	(84.9)
BAYSIDE 1	1.35%	94.77	95.2	93.8	401.1	(1,665.7)	94.7%	(121.6)
BAYSIDE 2	0.95%	79.96	81.4	77.1	280.9	(224.1)	80.3%	53.5
GPIF SYSTEM	**24.19%**				**7,191.3**	**(6,271.5)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	19.20%	10,468	92.9	9,836	11,101	5,705.6	(5,705.6)	10,467	0.0
BIG BEND 2	12.41%	10,272	92.9	9,862	10,682	3,688.3	(3,688.3)	10,356	(100.1)
BIG BEND 3	12.03%	10,614	86.1	10,209	11,018	3,576.1	(3,576.1)	10,595	0.0
BIG BEND 4	11.77%	10,549	88.0	10,157	10,941	3,499.1	(3,499.1)	10,420	593.2
POLK 1	6.81%	10,220	94.2	9,915	10,525	2,023.9	(2,023.9)	10,619	(2,023.9)
BAYSIDE 1	6.86%	7,248	82.6	7,120	7,377	2,040.2	(2,040.2)	7,206	0.0
BAYSIDE 2	6.73%	7,316	83.2	7,189	7,442	1,998.9	(1,998.9)	7,286	0.0
GPIF SYSTEM	**75.81%**					**22,532.3**	**(22,532.3)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2012 - DECEMBER 2012

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	67.0	0.8	67.8
BIG BEND 2	78.1	-1.4	76.7
BIG BEND 3	72.2	-2.9	69.3
BIG BEND 4	75.7	1.2	76.9
POLK 1	70.0	1.5	71.5
BAYSIDE 1	96.3	-1.6	94.7
BAYSIDE 2	78.8	1.5	80.3

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10479	-12	10467
BIG BEND 2	10391	-35	10356
BIG BEND 3	10637	-42	10595
BIG BEND 4	10437	-17	10420
POLK 1	10696	-77	10619
BAYSIDE 1	7223	-17	7206
BAYSIDE 2	7355	-69	7286

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 1
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 0.30%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	81.9	67.0	67.8
POH	504.0	600.0	504.0
FOH + EFOH	817.4	2239.0	2265.3
MOH + EMOH	271.6	59.7	60.4
POF	5.7	6.8	5.7
EFOF	9.3	25.5	25.8
EMOF	3.1	0.7	0.7
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 504}{8784 - 600} \times (2239 + 59.7) = 2325.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.7 - \frac{2325.7}{8784.0} \times 100 = 67.8$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 5.09%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	76.2	78.1	76.7
POH	504.0	353.5	504.0
FOH + EFOH	1466.0	1228.1	1206.2
MOH + EMOH	122.2	346.4	340.2
POF	5.7	4.0	5.7
EFOF	16.7	14.0	13.7
EMOF	1.4	3.9	3.9
	1.326	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 504}{8784 - 353.5} \times (1228.1 + 346.4) = 1546.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.7 - \frac{1546.4}{8784.0} \times 100 = 76.7$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 3
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 9.20%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	80.0	72.2	69.3
POH	576.0	247.3	576.0
FOH + EFOH	974.7	1887.2	1814.5
MOH + EMOH	208.1	310.0	298.1
POF	6.6	2.8	6.6
EFOF	11.1	21.5	20.7
EMOF	2.4	3.5	3.4
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 576}{8784 - 247.3} \times (1887.2 + 310) = 2112.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{2112.6}{8784.0} \times 100 = 69.3$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 6.50%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	77.4	75.7	76.9
POH	576.0	717.1	576.0
FOH + EFOH	1111.1	1102.1	1121.4
MOH + EMOH	297.3	318.2	323.8
POF	6.6	8.2	6.6
EFOF	12.6	12.5	12.8
EMOF	3.4	3.6	3.7
	-0.720	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 576}{8784 - 717.1} \times (1102.1 + 318.2) = 1445.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1445.1}{8784.0} \times 100 = 76.9$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 0.81%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	85.5	70.0	71.5
POH	960.0	1115.4	960.0
FOH + EFOH	177.7	1418.4	1447.1
MOH + EMOH	136.1	99.3	101.3
POF	10.9	12.7	10.9
EFOF	2.0	16.1	16.5
EMOF	1.5	1.1	1.2
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 960}{8784 - 1115.4} \times (1418.4 + 99.3) = 1548.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 10.9 - \frac{1548.5}{8784.0} \times 100 = 71.5$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 1
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 1.35%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	94.8	96.3	94.7
POH	336.0	190.0	336.0
FOH + EFOH	30.6	27.4	26.9
MOH + EMOH	92.9	106.1	104.3
POF	3.8	2.2	3.8
EFOF	0.3	0.3	0.3
EMOF	1.1	1.2	1.2
	-0.730	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 336}{8784 - 190} \times (27.4 + 106.1) = 131.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 3.8 - \frac{131.2}{8784.0} \times 100 = 94.7$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 2
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 0.95%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8784.0	8784.0	8784.0
EAF	80.0	78.8	80.3
POH	1511.0	1649.7	1511.0
FOH + EFOH	8.6	101.0	103.0
MOH + EMOH	240.8	115.1	117.3
POF	17.2	18.8	17.2
EFOF	0.1	1.1	1.2
EMOF	2.7	1.3	1.3
	2.387	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8784 - 1511}{8784 - 1649.7} \times (101 + 115.1) = 220.3$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 17.2 - \frac{220.3}{8784.0} \times 100 = 80.3$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 1
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 19.20%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10468	10479
NET GENERATION (GWH)	2682.5	2154.2
OPERATING BTU (10^9)	27394.1	22572.8
NET OUTPUT FACTOR	92.9	92.3

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-18.44) + 12181.88 = ANOHR

92.3 * (-18.44) + 12181.88 = 10480

10479 - 10480 = -1

10468 + -1 = 10467 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 12.41%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10272	10391
NET GENERATION (GWH)	2541.3	2519.2
OPERATING BTU (10^9)	26047.1	26177.2
NET OUTPUT FACTOR	92.9	88.2

-0.272 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-7.53) + 10970.84 = ANOHR

88.2 * (-7.53) + 10970.84 = 10307

10391 - 10307 = 84

10272 + 84 = 10356 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 12.03%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10614	10637
NET GENERATION (GWH)	2292.9	2220.0
OPERATING BTU (10^9)	23882.8	23613.5
NET OUTPUT FACTOR	86.1	84.1

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-20.71) + 12396.79 = ANOHR

84.1 * (-20.71) + 12396.79 = 10655

10637 - 10655 = -18

10614 + -18 = 10595 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 11.77%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10549	10437
NET GENERATION (GWH)	2640.4	2622.2
OPERATING BTU (10^9)	27265.0	27367.3
NET OUTPUT FACTOR	88.0	87.4

1.695 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-30.91) + 13267.86 = ANOHR

87.4 * (-30.91) + 13267.86 = 10566

10437 - 10566 = -129

10549 + -129 = 10420 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 6.81%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10220	10696
NET GENERATION (GWH)	1577.4	1194.9
OPERATING BTU (10^9)	16148.8	12780.5
NET OUTPUT FACTOR	94.2	92.5

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-45.48) + 14503.53 = ANOHR

92.5 * (-45.48) + 14503.53 = 10297

10696 - 10297 = 399

10220 + 399 = 10619 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 1
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 6.86%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7248	7223
NET GENERATION (GWH)	3190.4	3110.8
OPERATING BTU (10^9)	23898.5	22467.8
NET OUTPUT FACTOR	82.6	76.6

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-18.44) + 12181.88 = ANOHR

76.6 * (-2.82) + 7480.94 = 7265

7223 - 7265 = -42

7248 + -42 = 7206 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 2
JANUARY 2012 - DECEMBER 2012

WEIGHTING FACTOR = 6.73%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7316	7355
NET GENERATION (GWH)	4142.3	3931.0
OPERATING BTU (10^9)	30994.1	28910.7
NET OUTPUT FACTOR	83.2	75.0

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-18.44) + 12181.88 = ANOHR

75 * (-8.47) + 8020.05 = 7385

7355 - 7385 = -30

7316 + -30 = 7286 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

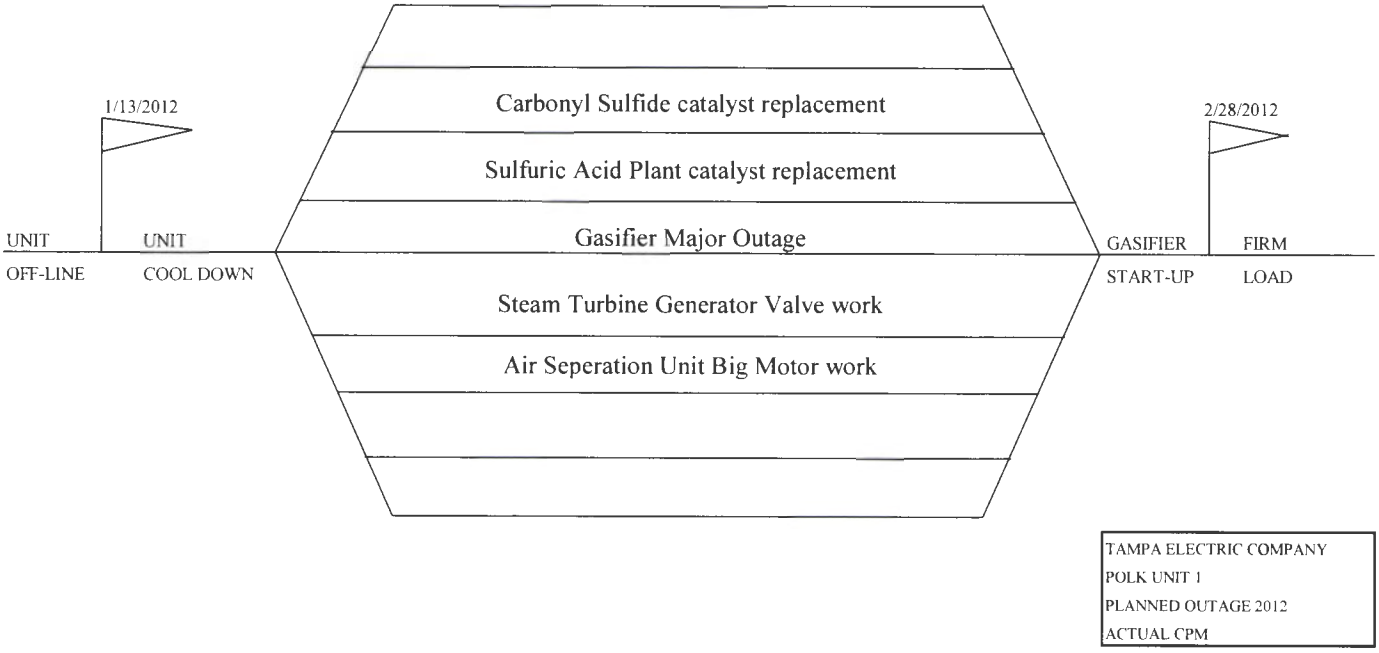
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2012 - DECEMBER 2012

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Apr 08	-	May 03	Fuel System Cleanup and Scrubber work
		Dec 08	-	Dec 14	Fuel System Cleanup and Scrubber work
	BIG BEND 2	Apr 16	-	Apr 30	Fuel System Cleanup and Scrubber work
	BIG BEND 3	Mar 03	-	Mar 13	Fuel System Cleanup and Scrubber work
	BIG BEND 4	May 05	-	May 18	Fuel System Cleanup and Scrubber work
		Sep 26	-	Oct 13	Fuel System Cleanup and Scrubber work
+	POLK 1	Jan 13	-	Feb 28	Commenced Major Outage, Steam Turbine Generator Valve work, Sulfuric Acid Plant catalyst replacement, Carbonyl Sulfide catalyst replacement, Air Seperation Unit Big Motor work
	BAYSIDE 1	Nov 12	-	Nov 18	Fuel System Cleanup
+	BAYSIDE 2	Feb 07	-	Apr 08	Commenced Major Outage, GSU replacement, Steam Path inspection, HP/IP/LP Steam Turbine Ring and Seal replacements, Steam Turbine Valve overhauls, Heat Exchanger replacements, Coarse Mesh Screen replacements, CT Major Overhauls and CT Inlet Filter replacements

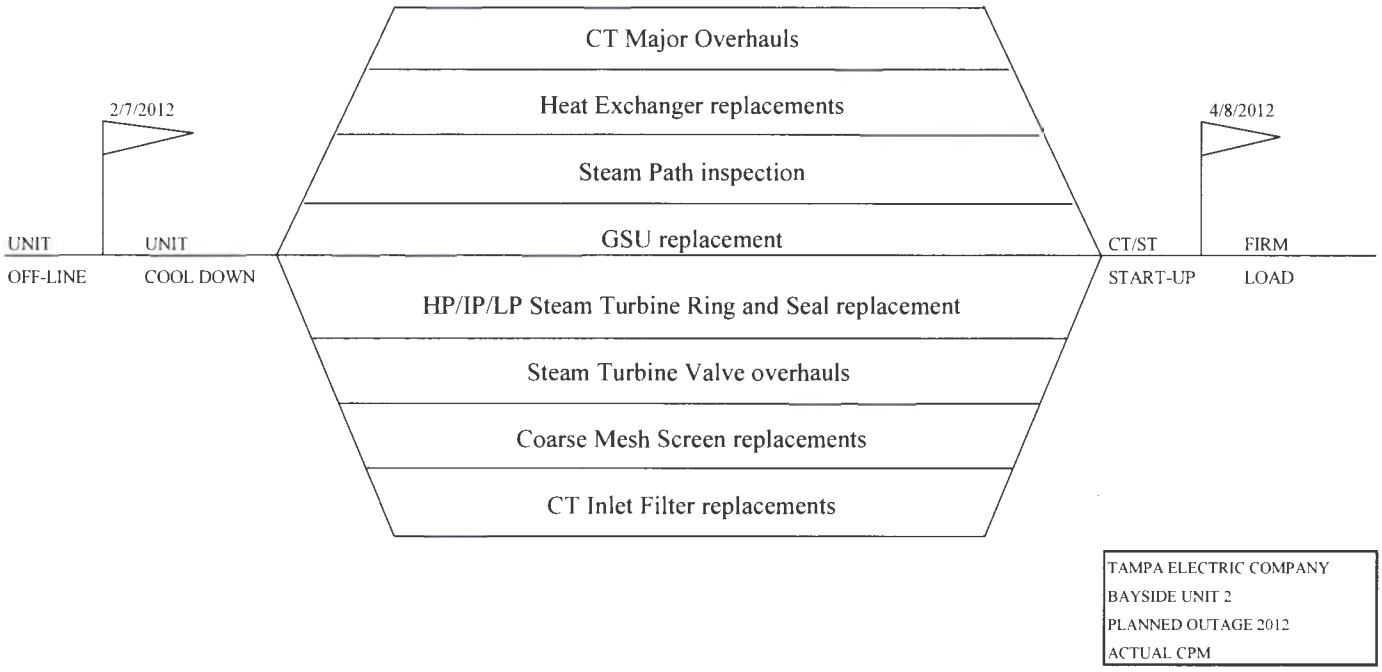
\+ **CPM for units with less than or equal to 4 weeks are not included.**

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2012 - DECEMBER 2012



TAMPA ELECTRIC COMPANY
POLK UNIT 1
PLANNED OUTAGE 2012
ACTUAL CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2012 - DECEMBER 2012



TAMPA ELECTRIC COMPANY
BAYSIDE UNIT 2
PLANNED OUTAGE 2012
ACTUAL CPM

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	89.3	84.6	+10	5,705.6	9,836
+9	80.4	84.4	+9	5,135.1	9,891
+8	71.4	84.1	+8	4,564.5	9,947
+7	62.5	83.8	+7	3,994.0	10,003
+6	53.6	83.5	+6	3,423.4	10,059
+5	44.7	83.2	+5	2,852.8	10,114
+4	35.7	83.0	+4	2,282.3	10,170
+3	26.8	82.7	+3	1,711.7	10,226
+2	17.9	82.4	+2	1,141.1	10,282
+1	8.9	82.1	+1	570.6	10,337
					10,393
0	0.0	81.9	0	0.0	10,468
					10,543
-1	(93.6)	81.3	-1	(570.6)	10,599
-2	(187.3)	80.8	-2	(1,141.1)	10,655
-3	(280.9)	80.2	-3	(1,711.7)	10,710
-4	(374.5)	79.7	-4	(2,282.3)	10,766
-5	(468.1)	79.1	-5	(2,852.8)	10,822
-6	(561.8)	78.5	-6	(3,423.4)	10,878
-7	(655.4)	78.0	-7	(3,994.0)	10,933
-8	(749.0)	77.4	-8	(4,564.5)	10,989
-9	(842.7)	76.9	-9	(5,135.1)	11,045
-10	(936.3)	76.3	-10	(5,705.6)	11,101

EAF POINTS -10.000

Adjusted EAF 67.8

AHR POINTS 0.000

Adjusted ANOHR 10,467

Weighting Factor = 0.30%

Weighting Factor = 19.20%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,512.2	80.1	+10	3,688.3	9,862
+9	1,360.9	79.7	+9	3,319.5	9,895
+8	1,209.7	79.3	+8	2,950.7	9,929
+7	1,058.5	78.9	+7	2,581.8	9,962
+6	907.3	78.5	+6	2,213.0	9,996
+5	756.1	78.1	+5	1,844.2	10,029
+4	604.9	77.7	+4	1,475.3	10,063
+3	453.6	77.4	+3	1,106.5	10,096
+2	302.4	77.0	+2	737.7	10,130
+1	151.2	76.6	+1	368.8	10,163
					10,197
0	0.0	76.2	0	0.0	10,272
					10,347
-1	(12.2)	75.4	-1	(368.8)	10,380
-2	(24.5)	74.6	-2	(737.7)	10,414
-3	(36.7)	73.8	-3	(1,106.5)	10,448
-4	(48.9)	73.1	-4	(1,475.3)	10,481
-5	(61.1)	72.3	-5	(1,844.2)	10,515
-6	(73.4)	71.5	-6	(2,213.0)	10,548
-7	(85.6)	70.7	-7	(2,581.8)	10,582
-8	(97.8)	69.9	-8	(2,950.7)	10,615
-9	(110.0)	69.2	-9	(3,319.5)	10,649
-10	(122.3)	68.4	-10	(3,688.3)	10,682

EAF POINTS 1.326

Adjusted EAF 76.7

AHR POINTS -0.272

Adjusted ANOHR 10,356

Weighting Factor = 5.09%

Weighting Factor = 12.41%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,734.4	83.0	+10	3,576.1	10,209
+9	2,461.0	82.7	+9	3,218.5	10,242
+8	2,187.5	82.4	+8	2,860.9	10,275
+7	1,914.1	82.1	+7	2,503.3	10,308
+6	1,640.6	81.8	+6	2,145.7	10,341
+5	1,367.2	81.5	+5	1,788.1	10,374
+4	1,093.8	81.2	+4	1,430.5	10,407
+3	820.3	80.9	+3	1,072.8	10,440
+2	546.9	80.6	+2	715.2	10,473
+1	273.4	80.3	+1	357.6	10,506
					10,539
0	0.0	80.0	0 (AHR POINTS 0.000)	0.0 (Adjusted ANOHR 10,595)	10,614
					10,689
-1	(168.5)	79.4	-1	(357.6)	10,722
-2	(337.0)	78.8	-2	(715.2)	10,755
-3	(505.5)	78.2	-3	(1,072.8)	10,788
-4	(674.0)	77.6	-4	(1,430.5)	10,820
-5	(842.5)	77.0	-5	(1,788.1)	10,853
-6	(1,011.0)	76.4	-6	(2,145.7)	10,886
-7	(1,179.5)	75.8	-7	(2,503.3)	10,919
-8	(1,348.0)	75.1	-8	(2,860.9)	10,952
-9	(1,516.5)	74.5	-9	(3,218.5)	10,985
-10 (EAF POINTS -10.000)	(1,685.0) (Adjusted EAF 69.3)	73.9	-10	(3,576.1)	11,018
Weighting Factor =		9.20%	Weighting Factor =		12.03%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,932.3	80.9	+10	3,499.1	10,157
+9	1,739.1	80.6	+9	3,149.2	10,188
+8	1,545.8	80.2	+8	2,799.3	10,220
+7	1,352.6	79.9	+7	2,449.4	10,252
+6	1,159.4	79.5	+6	2,099.5	10,283
+5	966.1	79.2	+5	1,749.5	10,315
+4	772.9	78.8	+4	1,399.6	10,347
+3	579.7	78.5	+3	1,049.7	10,379
+2	386.5	78.1	+2	699.8	10,410
+1	193.2	77.8	+1	349.9	10,442
					10,474
0	0.0	77.4	0	0.0	10,549
					10,624
-1	(155.3)	76.7	-1	(349.9)	10,656
-2	(310.7)	76.0	-2	(699.8)	10,687
-3	(466.0)	75.3	-3	(1,049.7)	10,719
-4	(621.3)	74.6	-4	(1,399.6)	10,751
-5	(776.6)	73.9	-5	(1,749.5)	10,782
-6	(932.0)	73.2	-6	(2,099.5)	10,814
-7	(1,087.3)	72.5	-7	(2,449.4)	10,846
-8	(1,242.6)	71.8	-8	(2,799.3)	10,878
-9	(1,397.9)	71.0	-9	(3,149.2)	10,909
-10	(1,553.3)	70.3	-10	(3,499.1)	10,941

EAF POINTS -0.720

Adjusted EAF 76.9

AHR POINTS 1.695

Adjusted ANOHR 10,420

Weighting Factor = 6.50%

Weighting Factor = 11.77%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	241.1	86.8	+10	2,023.9	9,915
+9	217.0	86.6	+9	1,821.5	9,938
+8	192.9	86.5	+8	1,619.1	9,961
+7	168.7	86.4	+7	1,416.7	9,984
+6	144.6	86.3	+6	1,214.4	10,007
+5	120.5	86.1	+5	1,012.0	10,030
+4	96.4	86.0	+4	809.6	10,053
+3	72.3	85.9	+3	607.2	10,076
+2	48.2	85.8	+2	404.8	10,099
+1	24.1	85.6	+1	202.4	10,122
					10,145
0	0.0	85.5	0	0.0	10,220
					10,295
-1	(8.5)	85.2	-1	(202.4)	10,318
-2	(17.0)	85.0	-2	(404.8)	10,341
-3	(25.5)	84.7	-3	(607.2)	10,364
-4	(33.9)	84.5	-4	(809.6)	10,387
-5	(42.4)	84.2	-5	(1,012.0)	10,410
-6	(50.9)	84.0	-6	(1,214.4)	10,433
-7	(59.4)	83.7	-7	(1,416.7)	10,456
-8	(67.9)	83.5	-8	(1,619.1)	10,479
-9	(76.4)	83.2	-9	(1,821.5)	10,502
-10	(84.9)	83.0	-10	(2,023.9)	10,525

Weighting Factor = 0.81%

Weighting Factor = 6.81%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	401.1	95.2	+10	2,040.2	7,120
+9	361.0	95.2	+9	1,836.2	7,125
+8	320.9	95.1	+8	1,632.2	7,130
+7	280.8	95.1	+7	1,428.2	7,136
+6	240.7	95.1	+6	1,224.1	7,141
+5	200.6	95.0	+5	1,020.1	7,146
+4	160.4	95.0	+4	816.1	7,152
+3	120.3	94.9	+3	612.1	7,157
+2	80.2	94.9	+2	408.0	7,163
+1	40.1	94.8	+1	204.0	7,168
					7,173
0	0.0	94.8	0	0.0	7,248
					7,323
-1	(166.6)	94.7	-1	(204.0)	7,329
-2	(333.1)	94.6	-2	(408.0)	7,334
-3	(499.7)	94.5	-3	(612.1)	7,339
-4	(666.3)	94.4	-4	(816.1)	7,345
-5	(832.8)	94.3	-5	(1,020.1)	7,350
-6	(999.4)	94.2	-6	(1,224.1)	7,355
-7	(1,166.0)	94.1	-7	(1,428.2)	7,361
-8	(1,332.6)	94.0	-8	(1,632.2)	7,366
-9	(1,499.1)	93.9	-9	(1,836.2)	7,371
-10	(1,665.7)	93.8	-10	(2,040.2)	7,377

EAF POINTS -0.730

Adjusted EAF 94.7

AHR POINTS 0.000

Adjusted ANOHR 7,206

Weighting Factor = 1.35%

Weighting Factor = 6.86%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2012 - DECEMBER 2012

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	280.9	81.4	+10	1,998.9	7,189
+9	252.8	81.2	+9	1,799.1	7,194
+8	224.7	81.1	+8	1,599.2	7,199
+7	196.6	81.0	+7	1,399.3	7,205
+6	168.5	80.8	+6	1,199.4	7,210
+5	140.5	80.7	+5	999.5	7,215
+4	112.4	80.5	+4	799.6	7,220
+3	84.3	80.4	+3	599.7	7,225
+2	56.2	80.2	+2	399.8	7,230
+1	28.1	80.1	+1	199.9	7,236
					7,241
0	0.0	80.0	0	0.0	7,316
					7,391
-1	(22.4)	79.7	-1	(199.9)	7,396
-2	(44.8)	79.4	-2	(399.8)	7,401
-3	(67.2)	79.1	-3	(599.7)	7,406
-4	(89.7)	78.8	-4	(799.6)	7,411
-5	(112.1)	78.5	-5	(999.5)	7,417
-6	(134.5)	78.2	-6	(1,199.4)	7,422
-7	(156.9)	78.0	-7	(1,399.3)	7,427
-8	(179.3)	77.7	-8	(1,599.2)	7,432
-9	(201.7)	77.4	-9	(1,799.1)	7,437
-10	(224.1)	77.1	-10	(1,998.9)	7,442

EAF POINTS 2.367 → Adjusted EAF 80.3

AHR POINTS 0.000 → Adjusted ANOHR 7,286

Weighting Factor = 0.95%

Weighting Factor = 6.73%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 12 - DEC 12 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 12 - DEC 12 POF	EUOF	EUOR
BIG BEND 1	0.30%	1.2%	5.7	12.4	13.2	6.8	26.2	28.1
BIG BEND 2	5.09%	21.0%	5.7	18.1	19.2	4.0	17.9	18.7
BIG BEND 3	9.20%	38.0%	6.6	13.5	14.4	2.8	25.0	25.7
BIG BEND 4	6.50%	26.9%	6.6	16.0	17.2	8.2	16.2	17.6
POLK 1	0.81%	3.4%	10.9	3.6	4.0	12.7	17.3	19.8
BAYSIDE 1	1.35%	5.6%	3.8	3.6	3.7	12.7	17.3	19.8
BAYSIDE 2	0.95%	3.9%	17.2	3.6	4.3	12.7	17.3	19.8
GPIF SYSTEM	**24.2%**	**100.0%**	**6.8**	**13.8**	**14.8**	**5.8**	**20.2**	**21.3**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (% 79.4 74.0

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
10.1	**16.2**	**18.1**	**73.7**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 12 - DEC 12	ADJUSTED ACTUAL HEAT RATE JAN 12 - DEC 12
BIG BEND 1	19.20%	25.3%	10,468	10,467
BIG BEND 2	12.41%	16.4%	10,272	10,356
BIG BEND 3	12.03%	15.9%	10,614	10,595
BIG BEND 4	11.77%	15.5%	10,549	10,420
POLK 1	6.81%	9.0%	10,220	10,619
BAYSIDE 1	6.86%	9.1%	7,248	7,206
BAYSIDE 2	6.73%	8.9%	7,316	7,286
GPIF SYSTEM	**75.8%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) 9,878 9,898

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2012 - DECEMBER 2012

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i(EAP_i) + e_i(AHRP_i) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP	0.30%	*	(BB 1 EAP)	+	5.09%	*	(BB 2 EAP)	+	9.20%	*	(BB 3 EAP)
+	6.50%	*	(BB 4 EAP)	+	0.81%	*	(PK 1 EAP)	+	1.35%	*	(BAY 1 EAP)
+	0.95%	*	(BAY 2 EAP)	+	19.20%	*	(BB 1 AHRP)	+	12.41%	*	(BB 2 AHRP)
+	12.03%	*	(BB 3 AHRP)	+	11.77%	*	(BB 4 AHRP)	+	6.81%	*	(PK 1 AHRP)
+	6.86%	*	(BAY 1 AHRP)	+	6.73%	*	(BAY 2 AHRP)				

GPIP =	0.30%	*	-10.000	+	5.09%	*	1.326	+	9.20%	*	-10.000
+	6.50%	*	-0.720	+	0.81%	*	-10.000	+	1.35%	*	-0.730
+	0.95%	*	2.387	+	19.20%	*	0.000	+	12.41%	*	-0.272
+	12.03%	*	0.000	+	11.77%	*	1.695	+	6.81%	*	-10.000
+	6.86%	*	0.000	+	6.73%	*	0.000				

GPIP =	-0.030	+	0.067	+	-0.920
+	-0.047	+	-0.081	+	-0.010
+	0.023	+	0.000	+	-0.034
+	0.000	+	0.200	+	-0.681
+	0.000	+	0.000		

GPIP = -1.513 POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF PENALTY = ($1,177,059)

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
GPIF 2012 FINAL TRUE-UP
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 130001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2012 - DECEMBER 2012

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	66.3	96.1	96.0	4.0	2.0	45.7	84.7	76.1	86.1	98.0	59.1	89.4	67.0
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	524.2	696.0	743.0	28.5	35.8	358.3	634.9	581.6	626.6	744.0	432.3	602.6	6,007.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	66.1	66.1
5. UH	219.8	0.0	0.0	691.5	708.2	361.7	109.1	162.4	93.4	0.0	288.7	75.3	2,710.2
6. POH	0.0	0.0	0.0	552.0	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0
7. FOH	219.8	0.0	0.0	139.5	660.2	361.7	109.1	162.4	93.4	0.0	288.7	75.3	2,110.2
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	295.2	432.5	471.9	0.0	35.8	223.3	7.6	20.7	40.4	81.3	11.1	68.7	1,688.3
10. LR PF (MW)	33.3	15.7	13.7	0.0	227.1	45.8	140.9	87.8	30.2	19.6	140.6	18.5	29.6
11. PMOH	20.4	51.5	47.2	0.0	0.0	5.5	5.8	37.8	9.6	29.0	5.1	0.0	211.8
12. LR PM (MW)	112.3	75.0	110.4	0.0	0.0	165.9	105.0	111.8	134.2	141.2	136.5	0.0	109.4
13. NSC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3
14. OPR BTU(GBTU)	1,880.0	2,568.8	2,753.6	114.3	43.7	1,292.6	2,493.9	2,262.6	2,443.2	2,796.5	1,550.4	2,373.3	22,572.8
15. NET GEN (MWH)	182,370	249,783	267,166	10,989	4,308	121,312	240,845	211,771	227,394	264,740	147,843	225,667	2,154,188
16. ANOHR (BTU/KWH)	10,308.6	10,284.2	10,306.6	10,398.0	10,153.3	10,655.3	10,354.6	10,684.3	10,744.3	10,563.3	10,486.5	10,516.6	10,479.0
17. NOF (%)	88.1	90.9	91.0	100.3	31.3	87.9	98.5	94.6	94.3	92.4	88.8	94.8	92.3
18. NPC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3

19. ANOHR EQUATION ANOHR = NOF(-18.440)+ 12182

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 1 OF 7

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	95.5	87.9	64.2	50.1	94.3	87.2	86.3	83.9	57.7	92.1	78.4	58.6	78.1
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	736.7	696.0	632.2	366.5	734.1	696.2	696.9	633.6	432.2	709.5	579.9	440.3	7,354.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	7.3	0.0	110.8	353.5	9.9	23.8	47.1	110.4	287.8	34.5	141.1	303.7	1,429.9
6. POH	0.0	0.0	0.0	353.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	353.5
7. FOH	0.0	0.0	0.0	0.0	9.9	23.8	0.0	0.0	287.8	34.5	141.1	303.7	800.8
8. MOH	7.3	0.0	110.8	0.0	0.0	0.0	47.1	110.4	0.0	0.0	0.0	0.0	275.7
9. PFOH	70.2	622.4	550.3	132.5	335.6	690.3	686.9	27.4	7.5	77.1	39.0	18.1	3,257.4
10. LR PF (MW)	70.6	46.6	111.2	13.3	31.3	38.1	29.9	14.7	90.9	81.7	92.0	41.5	50.9
11. PMOH	31.8	26.5	0.0	3.4	8.3	1.0	2.3	23.9	25.7	23.2	14.2	4.3	164.5
12. LR PM (MW)	165.7	159.8	0.0	121.6	236.1	150.2	178.5	134.1	220.6	136.4	153.3	192.4	166.9
13. NSC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3
14. OPR BTU(GBTU)	2,611.9	2,310.8	1,870.2	1,352.5	2,584.3	2,435.7	2,503.3	2,434.2	1,599.2	2,596.0	2,153.5	1,725.8	26,177.2
15. NET GEN (MWH)	261,282	228,186	181,488	133,918	253,136	232,215	237,196	232,530	150,357	241,512	203,738	163,607	2,519,165
16. ANOHR (BTU/KWH)	9,996.6	10,126.7	10,304.6	10,099.1	10,209.0	10,488.9	10,553.7	10,468.5	10,635.9	10,748.8	10,569.8	10,548.3	10,391.0
17. NOF (%)	89.8	83.0	72.7	94.9	89.6	86.6	88.4	95.3	90.4	88.4	91.3	94.1	88.2
18. NPC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3
19. ANOHR EQUATION	ANOHR = NOF(-7.525) + 10971												

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 2 OF 7

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	81.7	86.2	58.1	70.7	84.1	48.9	50.9	73.1	81.6	72.4	74.9	84.0	72.2
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	611.8	693.3	495.7	510.1	629.2	392.4	457.6	645.8	720.0	688.2	643.8	744.0	7,231.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	132.3	2.8	247.3	210.0	114.8	327.6	286.4	98.2	0.0	55.9	77.2	0.0	1,552.3
6. POH	0.0	0.0	247.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	247.3
7. FOH	132.3	2.8	0.0	154.6	114.8	327.6	286.4	98.2	0.0	55.9	3.4	0.0	1,175.8
8. MOH	0.0	0.0	0.0	55.4	0.0	0.0	0.0	0.0	0.0	0.0	73.8	0.0	129.2
9. PFOH	3.7	229.7	318.5	7.1	2.0	71.2	429.9	637.6	661.9	318.7	593.8	737.0	4,011.0
10. LR PF (MW)	61.2	116.2	68.1	53.3	102.2	105.8	56.2	56.9	57.4	85.7	59.3	57.1	64.7
11. PMOH	11.6	64.4	9.1	0.0	6.8	76.8	27.7	8.3	58.1	365.2	49.0	7.0	683.8
12. LR PM (MW)	95.4	114.8	173.3	0.0	163.5	95.3	167.6	124.8	176.9	75.0	56.2	206.0	96.5
13. NSC (MW)	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0
14. OPR BTU(GBTU)	2,168.5	2,204.1	1,575.2	1,832.3	2,329.6	1,311.8	1,449.7	2,099.8	2,297.9	2,032.3	1,972.3	2,340.0	23,613.5
15. NET GEN (MWH)	211,982	212,105	151,091	177,651	221,808	120,084	132,924	192,711	206,929	187,121	186,394	219,202	2,220,002
16. ANOHR BTU/KWH	10,229.5	10,391.4	10,425.4	10,314.1	10,502.6	10,924.1	10,906.6	10,896.3	11,105.0	10,860.8	10,581.3	10,675.0	10,637.0
17. NOF (%)	94.9	83.8	83.5	95.4	96.6	83.8	79.6	81.8	78.7	74.5	79.3	80.7	84.1
18. NPC (MW)	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0	365.0
19. ANOHR EQUATION	ANOHR = NOF(-20.706) + 12397												

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 3 OF 7

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	97.6	99.3	97.7	79.0	38.1	81.3	61.8	99.4	78.5	54.2	76.3	47.0	75.7
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	740.9	696.0	743.0	712.8	407.5	689.3	516.4	744.0	572.0	414.8	560.3	428.4	7,225.3
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	3.1	0.0	0.0	7.3	336.5	30.7	227.7	0.0	148.0	329.2	160.7	315.6	1,558.7
6. POH	0.0	0.0	0.0	0.0	323.6	0.0	0.0	0.0	98.8	294.6	0.0	0.0	717.1
7. FOH	3.1	0.0	0.0	7.3	12.9	30.7	227.7	0.0	49.2	34.6	160.7	80.6	606.7
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	235.0
9. PFOH	22.3	0.0	271.0	606.9	288.0	402.8	278.4	23.5	218.2	20.8	30.5	288.3	2,450.7
10. LR PF (MW)	43.3	0.0	24.9	98.9	128.2	98.5	62.7	78.5	10.6	197.0	136.2	109.5	84.0
11. PMOH	24.2	9.4	3.2	0.0	61.8	28.7	24.6	0.0	1.6	3.3	0.0	5.8	162.5
12. LR PM (MW)	226.7	232.3	129.3	0.0	240.6	130.5	230.1	0.0	204.8	176.0	0.0	227.7	212.7
13. NSC (MW)	427.0	427.0	427.0	417.0	417.0	417.0	407.0	407.0	407.0	407.0	407.0	417.0	415.3
14. OPR BTU(GBTU)	3,006.3	2,865.8	2,965.9	2,469.2	1,181.7	2,512.5	1,892.8	3,073.4	2,358.9	1,521.7	2,101.7	1,417.4	27,367.3
15. NET GEN (MWH)	289,036	279,663	294,024	236,477	105,642	236,731	181,613	294,808	221,321	145,757	203,116	134,039	2,622,227
16. ANOHR BTU/KWH	10,401.0	10,247.4	10,087.4	10,441.5	11,185.8	10,613.4	10,422.1	10,425.2	10,658.2	10,440.2	10,347.2	10,574.4	10,437.0
17. NOF (%)	91.4	94.1	92.7	79.6	62.2	82.4	86.4	97.4	95.1	86.3	89.1	75.0	87.4
18. NPC (MW)	427.0	427.0	427.0	417.0	417.0	417.0	407.0	407.0	407.0	407.0	407.0	417.0	415.3
19. ANOHR EQUATION	ANOHR = NOF(-30.914) + 13268												

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 4 OF 7

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	21.7	1.7	96.3	97.7	73.0	0.0	81.1	100.0	89.3	99.7	92.0	83.3	70.0
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	113.0	2.9	681.9	698.3	563.5	0.0	565.8	744.0	566.8	744.0	666.8	524.6	5,871.6
4. RSH	49.8	9.0	40.1	20.1	0.0	0.0	57.7	0.0	111.6	0.0	0.0	137.7	425.9
5. UH	581.2	684.1	21.1	1.6	180.5	720.0	120.5	0.0	41.6	0.0	54.2	81.7	2,486.5
6. POH	449.0	666.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,115.4
7. FOH	132.2	0.0	4.1	1.6	180.5	720.0	120.5	0.0	0.0	0.0	54.2	58.7	1,271.8
8. MOH	0.0	17.7	17.0	0.0	0.0	0.0	0.0	0.0	41.6	0.0	0.0	23.0	99.3
9. PFOH	5.8	0.0	27.8	67.6	92.5	0.0	88.8	5.2	249.4	64.6	16.0	188.4	806.0
10. LR PF (MW)	49.1	0.0	49.4	47.6	49.3	0.0	49.0	7.7	31.4	7.7	49.4	49.3	40.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
14. OPR BTU(GBTU)	273.3	2.1	1,199.5	1,508.5	1,082.6	0.0	1,253.6	1,769.2	1,301.9	1,672.5	1,507.7	1,209.7	12,780.5
15. NET GEN (MWH)	22,381	-2,681	110,360	148,524	101,347	-4,275	116,387	165,849	116,430	163,044	146,108	111,441	1,194,915
16. ANOHR BTU/KWH	12,209.3	0.0	10,869.2	10,156.8	10,681.8	0.0	10,770.6	10,667.4	11,181.7	10,257.8	10,319.4	10,855.1	10,696.0
17. NOF (%)	90.0	0.0	73.6	96.7	81.7	0.0	93.5	101.3	93.4	99.6	99.6	96.6	92.5
18. NPC (MW)	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0

19. ANOHR EQUATION ANOHR = NOF(-45.481) + 14504

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 5 OF 7

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE UNIT 1	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	100.0	97.4	100.0	98.4	91.8	99.6	99.3	99.0	99.6	97.4	73.0	100.0	96.3
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	0.0	464.6	630.1	620.2	610.1	640.8	629.5	590.7	595.9	538.3	236.2	0.0	5,556.3
4. RSH	744.0	213.5	112.9	88.4	72.8	76.2	109.2	146.0	121.1	186.1	290.0	744.0	2,904.2
5. UH	0.0	18.0	0.0	11.5	61.1	3.0	5.3	7.3	3.0	19.5	194.8	0.0	323.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	190.0	0.0	190.0
7. FOH	0.0	18.0	0.0	0.0	0.5	0.0	0.0	0.5	0.0	3.5	4.8	0.0	27.4
8. MOH	0.0	0.0	0.0	11.5	60.6	3.0	5.3	6.8	3.0	16.0	0.0	0.0	106.1
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	1.1
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.7
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	792.0	792.0	792.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	792.0	731.3
14. OPR BTU(GBTU)	0.0	1,851.4	2,604.8	2,689.4	2,542.3	2,741.6	2,645.0	2,369.9	2,460.7	2,029.4	533.3	0.0	22,467.8
15. NET GEN (MWH)	-889	252,257	358,225	375,788	355,736	383,209	368,522	328,239	341,680	278,552	71,528	-2,050	3,110,796
16. ANOHR (BTU/KWH)	0.0	7,339.5	7,271.3	7,156.8	7,146.6	7,154.4	7,177.2	7,220.1	7,201.7	7,285.4	7,455.4	0.0	7,223.0
17. NOF (%)	0.0	68.6	71.8	86.4	83.2	85.3	83.5	79.3	81.8	73.8	43.2	0.0	76.6
18. NPC (MW)	792.0	792.0	792.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	701.0	792.0	731.3

19. ANOHR EQUATION ANOHR = NOF(-2.816) + 7481

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 6 OF 7

ORIGINAL SHEET NO. 8.401.12A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2012 - DECEMBER 2012

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE UNIT 2	JAN 12	FEB 12	MAR 12	APR 12	MAY 12	JUN 12	JUL 12	AUG 12	SEP 12	OCT 12	NOV 12	DEC 12	2012
1. EAF (%)	100.0	18.8	0.0	55.1	88.2	96.4	98.4	100.0	98.5	99.0	98.9	88.7	78.8
2. PH	744	696	743	720	744	720	744	744	720	744	721	744	8,784
3. SH	559.7	90.1	0.0	364.0	606.4	600.4	631.1	566.5	557.6	430.6	438.5	565.9	5,410.7
4. RSH	184.3	40.6	0.0	32.6	50.9	94.2	100.8	177.5	151.8	305.9	274.8	94.2	1,507.6
5. UH	0.0	565.3	743.0	323.4	86.7	25.4	12.1	0.0	10.6	7.5	7.7	84.0	1,865.7
6. POH	0.0	565.3	743.0	282.6	58.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,649.7
7. FOH	0.0	0.0	0.0	20.7	17.2	8.1	0.2	0.0	0.1	0.0	0.6	53.9	101.0
8. MOH	0.0	0.0	0.0	20.1	10.7	17.3	11.9	0.0	10.5	7.5	7.0	30.0	115.1
9. PFOH	0.0	0.0	0.0	0.0	49.0	8.5	0.0	0.0	0.2	0.0	0.0	0.0	57.7
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.6	0.0	0.0	0.0	0.5
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	1,047.0	1,047.0	1,047.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	1,047.0	968.3
14. OPR BTU(GBTU)	3,003.9	440.3	0.0	1,524.7	3,388.3	3,460.8	3,613.2	3,079.2	3,090.3	2,205.3	2,040.5	3,064.2	28,910.7
15. NET GEN (MWH)	410,872	57,812	-2,561	202,074	465,535	474,208	494,379	417,171	420,322	297,191	273,547	420,442	3,930,991
16. ANOHR (BTU/KWH)	7,311.1	7,616.0	0.0	7,545.1	7,278.3	7,298.2	7,308.7	7,381.1	7,352.2	7,420.5	7,459.4	7,288.0	7,355.0
17. NOF (%)	70.1	61.3	0.0	59.8	82.6	85.0	84.3	79.3	81.1	74.3	67.1	71.0	75.0
18. NPC (MW)	1,047.0	1,047.0	1,047.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	929.0	1,047.0	968.3

19. ANOHR EQUATION ANOHR = NOF(-8.469) + 8020

EXHIBIT NO. ____ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 130001 - EI
DOCUMENT NO. 2
PAGE 7 OF 7

DOCKET NO. 130001-EI
GPIF 2014 PROJECTION FILING
EXHIBIT NO. ____ (BSB-2)
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2014 - DECEMBER 2014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 50
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Brian S. Buckley - BSB-2

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2014 - DECEMBER 2014
TARGETS
TABLE OF CONTENTS

SCHEDULE	PAGE
GPIF REWARD / PENALTY TABLE	2
GPIF CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS	3
GPIF TARGET AND RANGE SUMMARY	4
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE	5
DERIVATION OF WEIGHTING FACTORS	6
GPIF TARGET AND RANGE SUMMARY	7 - 13
ESTIMATED UNIT PERFORMANCE DATA	14 - 20
ESTIMATED PLANNED OUTAGE SCHEDULE	21
CRITICAL PATH METHOD DIAGRAMS	22 - 23
FORCED & MAINTENANCE OUTAGE FACTOR GRAPHS	24 - 30
HEAT RATE VS NET OUTPUT FACTOR GRAPHS	31 - 37
GENERATING UNITS IN GPIF (TABLE 4.2 IN THE MANUAL)	38
UNIT RATINGS AS OF JULY 2013	39
PROJECTED PERCENT GENERATION BY UNIT	40

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2014 - DECEMBER 2014

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	14,961.9	7,480.9
+9	13,465.7	6,732.9
+8	11,969.5	5,984.8
+7	10,473.3	5,236.7
+6	8,977.1	4,488.6
+5	7,480.9	3,740.5
+4	5,984.8	2,992.4
+3	4,488.6	2,244.3
+2	2,992.4	1,496.2
+1	1,496.2	748.1
0	0.0	0.0
-1	(1,454.1)	(748.1)
-2	(2,908.1)	(1,496.2)
-3	(4,362.2)	(2,244.3)
-4	(5,816.3)	(2,992.4)
-5	(7,270.4)	(3,740.5)
-6	(8,724.4)	(4,488.6)
-7	(10,178.5)	(5,236.7)
-8	(11,632.6)	(5,984.8)
-9	(13,086.6)	(6,732.9)
-10	(14,540.7)	(7,480.9)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2014 - DECEMBER 2014

Line 1	Beginning of period balance of common equity: End of month common equity:		$2,034,838,000
Line 2	Month of January	2014	$1,988,303,000
Line 3	Month of February	2014	$2,006,943,341
Line 4	Month of March	2014	$2,025,758,434
Line 5	Month of April	2014	$2,053,829,485
Line 6	Month of May	2014	$2,073,084,137
Line 7	Month of June	2014	$2,092,519,301
Line 8	Month of July	2014	$2,045,375,803
Line 9	Month of August	2014	$2,064,551,201
Line 10	Month of September	2014	$2,083,906,369
Line 11	Month of October	2014	$2,112,055,923
Line 12	Month of November	2014	$2,131,856,447
Line 13	Month of December	2014	$2,151,842,601
Line 14	(Summation of line 1 through line 13 divided by 13)		$2,066,528,003
Line 15	25 Basis points		0.0025
Line 16	Revenue Expansion Factor		61.17%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$8,446,336
Line 18	Jurisdictional Sales		18,352,207 MWH
Line 19	Total Sales		18,352,207 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		100.00%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$8,446,336**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2014 - DECEMBER 2014

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	8.03%	60.6	65.0	51.8	1,201.3	(428.6)
BIG BEND 2	0.71%	74.9	78.9	66.8	106.0	(550.0)
BIG BEND 3	4.89%	74.1	78.3	65.7	732.4	(564.5)
BIG BEND 4	3.06%	62.6	67.4	53.1	457.2	(271.5)
POLK 1	1.66%	84.0	86.4	79.1	248.0	(259.2)
BAYSIDE 1	5.89%	94.0	94.4	93.1	880.8	(341.8)
BAYSIDE 2	8.67%	85.8	87.9	81.6	1,296.6	(2,085.3)
GPIF SYSTEM	**32.90%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	13.20%	10,501	94.0	10,200	10,802	1,975.3	(1,975.3)
BIG BEND 2	11.67%	10,271	93.0	10,057	10,485	1,746.0	(1,746.0)
BIG BEND 3	8.77%	10,696	82.1	10,523	10,870	1,312.2	(1,312.2)
BIG BEND 4	8.96%	10,381	88.3	10,195	10,568	1,340.6	(1,340.6)
POLK 1	5.05%	10,506	96.5	10,365	10,647	755.0	(755.0)
BAYSIDE 1	10.47%	7,283	60.4	7,164	7,401	1,566.1	(1,566.1)
BAYSIDE 2	8.99%	7,387	59.1	7,310	7,463	1,344.6	(1,344.6)
GPIF SYSTEM	**67.10%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 14 - DEC 14 POF	TARGET PERIOD JAN 14 - DEC 14 EUOF	TARGET PERIOD JAN 14 - DEC 14 EUOR	ACTUAL PERFORMANCE JAN 12 - DEC 12 POF	ACTUAL PERFORMANCE JAN 12 - DEC 12 EUOF	ACTUAL PERFORMANCE JAN 12 - DEC 12 EUOR	ACTUAL PERFORMANCE JAN 11 - DEC 11 POF	ACTUAL PERFORMANCE JAN 11 - DEC 11 EUOF	ACTUAL PERFORMANCE JAN 11 - DEC 11 EUOR	ACTUAL PERFORMANCE JAN 10 - DEC 10 POF	ACTUAL PERFORMANCE JAN 10 - DEC 10 EUOF	ACTUAL PERFORMANCE JAN 10 - DEC 10 EUOR
BIG BEND 1	8.03%	24.4%	23.0	16.4	21.2	6.8	26.2	28.3	5.8	13.5	14.4	24.5	15.1	19.9
BIG BEND 2	0.71%	2.2%	6.6	18.6	19.9	4.0	17.9	18.7	17.1	25.4	30.6	5.5	26.1	27.6
BIG BEND 3	4.89%	14.9%	6.6	19.4	20.7	2.8	25.0	25.7	8.6	17.9	19.5	8.4	11.9	13.1
BIG BEND 4	3.06%	9.3%	18.1	19.3	23.5	8.2	16.2	17.6	9.4	15.1	16.7	19.3	14.2	17.5
POLK 1	1.66%	5.0%	5.2	10.8	11.4	12.7	17.3	18.9	4.4	17.3	17.6	4.8	5.2	5.7
BAYSIDE 1	5.89%	17.9%	4.9	1.1	1.1	1.9	3.0	2.0	21.0	3.3	2.0	4.2	2.9	1.1
BAYSIDE 2	8.67%	26.3%	4.9	9.3	9.8	16.5	7.5	2.9	3.7	7.4	3.2	7.6	4.3	1.9
GPIF SYSTEM	**32.90%**	**100.0%**	**10.9**	**12.2**	**14.2**	**8.3**	**15.4**	**14.9**	**8.9**	**11.3**	**10.7**	**12.1**	**9.3**	**10.0**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**76.9**			**76.4**			**79.8**			**78.6**	

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
9.8	**12.0**	**11.9**	**78.3**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 14 - DEC 14	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 12 - DEC 12	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 11 - DEC 11	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 10 - DEC 10
BIG BEND 1	13.20%	19.7%	10,501	10,470	10,665	10,213
BIG BEND 2	11.67%	17.4%	10,271	10,328	10,224	10,107
BIG BEND 3	8.77%	13.1%	10,696	10,690	10,628	10,852
BIG BEND 4	8.96%	13.4%	10,381	10,417	10,349	10,383
POLK 1	5.05%	7.5%	10,506	10,167	10,687	10,203
BAYSIDE 1	10.47%	15.6%	7,283	7,261	7,244	7,245
BAYSIDE 2	8.99%	13.4%	7,387	7,349	7,358	7,384
GPIF SYSTEM	**67.10%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,552**	**9,526**	**9,566**	**9,458**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2014 - DECEMBER 2014
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	724,400.4	723,199.1	1,201.3	8.03%
EA_2 BIG BEND 2	724,400.4	724,294.4	106.0	0.71%
EA_3 BIG BEND 3	724,400.4	723,668.0	732.4	4.89%
EA_4 BIG BEND 4	724,400.4	723,943.2	457.2	3.06%
EA_5 POLK 1	724,400.4	724,152.4	248.0	1.66%
EA_6 BAYSIDE 1	724,400.4	723,519.6	880.8	5.89%
EA_7 BAYSIDE 2	724,400.4	723,103.8	1,296.6	8.67%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	724,400.4	722,425.1	1,975.3	13.20%
AHR_2 BIG BEND 2	724,400.4	722,654.4	1,746.0	11.67%
AHR_3 BIG BEND 3	724,400.4	723,088.2	1,312.2	8.77%
AHR_4 BIG BEND 4	724,400.4	723,059.8	1,340.6	8.96%
AHR_5 POLK 1	724,400.4	723,645.4	755.0	5.05%
AHR_6 BAYSIDE 1	724,400.4	722,834.3	1,566.1	10.47%
AHR_7 BAYSIDE 2	724,400.4	723,055.8	1,344.6	8.99%
TOTAL SAVINGS			**14,961.9**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,201.3	65.0	+10	1,975.3	10,200
+9	1,081.2	64.6	+9	1,777.7	10,223
+8	961.0	64.2	+8	1,580.2	10,245
+7	840.9	63.7	+7	1,382.7	10,268
+6	720.8	63.3	+6	1,185.2	10,290
+5	600.6	62.8	+5	987.6	10,313
+4	480.5	62.4	+4	790.1	10,336
+3	360.4	61.9	+3	592.6	10,358
+2	240.3	61.5	+2	395.1	10,381
+1	120.1	61.1	+1	197.5	10,404
					10,426
0	0.0	60.6	0	0.0	10,501
					10,576
-1	(42.9)	59.7	-1	(197.5)	10,599
-2	(85.7)	58.9	-2	(395.1)	10,621
-3	(128.6)	58.0	-3	(592.6)	10,644
-4	(171.4)	57.1	-4	(790.1)	10,667
-5	(214.3)	56.2	-5	(987.6)	10,689
-6	(257.2)	55.3	-6	(1,185.2)	10,712
-7	(300.0)	54.4	-7	(1,382.7)	10,734
-8	(342.9)	53.5	-8	(1,580.2)	10,757
-9	(385.7)	52.7	-9	(1,777.7)	10,780
-10	(428.6)	51.8	-10	(1,975.3)	10,802
	Weighting Factor =	8.03%		Weighting Factor =	13.20%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	106.0	78.9	+10	1,746.0	10,057
+9	95.4	78.5	+9	1,571.4	10,071
+8	84.8	78.1	+8	1,396.8	10,085
+7	74.2	77.7	+7	1,222.2	10,099
+6	63.6	77.3	+6	1,047.6	10,113
+5	53.0	76.9	+5	873.0	10,127
+4	42.4	76.5	+4	698.4	10,140
+3	31.8	76.1	+3	523.8	10,154
+2	21.2	75.7	+2	349.2	10,168
+1	10.6	75.3	+1	174.6	10,182
					10,196
0	0.0	74.9	0	0.0	10,271
					10,346
-1	(55.0)	74.1	-1	(174.6)	10,360
-2	(110.0)	73.2	-2	(349.2)	10,374
-3	(165.0)	72.4	-3	(523.8)	10,388
-4	(220.0)	71.6	-4	(698.4)	10,401
-5	(275.0)	70.8	-5	(873.0)	10,415
-6	(330.0)	70.0	-6	(1,047.6)	10,429
-7	(385.0)	69.2	-7	(1,222.2)	10,443
-8	(440.0)	68.4	-8	(1,396.8)	10,457
-9	(495.0)	67.6	-9	(1,571.4)	10,471
-10	(550.0)	66.8	-10	(1,746.0)	10,485
	Weighting Factor =	0.71%		Weighting Factor =	11.67%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	732.4	78.3	+10	1,312.2	10,523
+9	659.1	77.9	+9	1,181.0	10,533
+8	585.9	77.4	+8	1,049.7	10,542
+7	512.7	77.0	+7	918.5	10,552
+6	439.4	76.6	+6	787.3	10,562
+5	366.2	76.2	+5	656.1	10,572
+4	292.9	75.8	+4	524.9	10,582
+3	219.7	75.3	+3	393.7	10,592
+2	146.5	74.9	+2	262.4	10,602
+1	73.2	74.5	+1	131.2	10,611
					10,621
0	0.0	74.1	0	0.0	10,696
					10,771
-1	(56.5)	73.2	-1	(131.2)	10,781
-2	(112.9)	72.4	-2	(262.4)	10,791
-3	(169.4)	71.6	-3	(393.7)	10,801
-4	(225.8)	70.7	-4	(524.9)	10,811
-5	(282.3)	69.9	-5	(656.1)	10,821
-6	(338.7)	69.0	-6	(787.3)	10,831
-7	(395.2)	68.2	-7	(918.5)	10,840
-8	(451.6)	67.4	-8	(1,049.7)	10,850
-9	(508.1)	66.5	-9	(1,181.0)	10,860
-10	(564.5)	65.7	-10	(1,312.2)	10,870
	Weighting Factor =	4.89%		Weighting Factor =	8.77%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	457.2	67.4	+10	1,340.6	10,195
+9	411.5	66.9	+9	1,206.5	10,206
+8	365.8	66.4	+8	1,072.5	10,217
+7	320.1	66.0	+7	938.4	10,229
+6	274.3	65.5	+6	804.3	10,240
+5	228.6	65.0	+5	670.3	10,251
+4	182.9	64.5	+4	536.2	10,262
+3	137.2	64.1	+3	402.2	10,273
+2	91.4	63.6	+2	268.1	10,284
+1	45.7	63.1	+1	134.1	10,295
					10,306
0	0.0	62.6	0	0.0	10,381
					10,456
-1	(27.2)	61.7	-1	(134.1)	10,468
-2	(54.3)	60.7	-2	(268.1)	10,479
-3	(81.5)	59.8	-3	(402.2)	10,490
-4	(108.6)	58.8	-4	(536.2)	10,501
-5	(135.8)	57.9	-5	(670.3)	10,512
-6	(162.9)	56.9	-6	(804.3)	10,523
-7	(190.1)	56.0	-7	(938.4)	10,534
-8	(217.2)	55.0	-8	(1,072.5)	10,546
-9	(244.4)	54.1	-9	(1,206.5)	10,557
-10	(271.5)	53.1	-10	(1,340.6)	10,568
	Weighting Factor =	3.06%		Weighting Factor =	8.96%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	248.0	86.4	+10	755.0	10,365
+9	223.2	86.2	+9	679.5	10,372
+8	198.4	85.9	+8	604.0	10,379
+7	173.6	85.7	+7	528.5	10,385
+6	148.8	85.4	+6	453.0	10,392
+5	124.0	85.2	+5	377.5	10,398
+4	99.2	84.9	+4	302.0	10,405
+3	74.4	84.7	+3	226.5	10,412
+2	49.6	84.5	+2	151.0	10,418
+1	24.8	84.2	+1	75.5	10,425
					10,431
0	0.0	84.0	0	0.0	10,506
					10,581
-1	(25.9)	83.5	-1	(75.5)	10,588
-2	(51.8)	83.0	-2	(151.0)	10,595
-3	(77.8)	82.5	-3	(226.5)	10,601
-4	(103.7)	82.0	-4	(302.0)	10,608
-5	(129.6)	81.6	-5	(377.5)	10,614
-6	(155.5)	81.1	-6	(453.0)	10,621
-7	(181.5)	80.6	-7	(528.5)	10,627
-8	(207.4)	80.1	-8	(604.0)	10,634
-9	(233.3)	79.6	-9	(679.5)	10,641
-10	(259.2)	79.1	-10	(755.0)	10,647
	Weighting Factor =	1.66%		Weighting Factor =	5.05%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BAYSIDE 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	880.8	94.45	+10	1,566.1	7,164
+9	792.8	94.40	+9	1,409.5	7,169
+8	704.7	94.35	+8	1,252.9	7,173
+7	616.6	94.31	+7	1,096.3	7,177
+6	528.5	94.26	+6	939.6	7,182
+5	440.4	94.21	+5	783.0	7,186
+4	352.3	94.17	+4	626.4	7,190
+3	264.3	94.12	+3	469.8	7,195
+2	176.2	94.07	+2	313.2	7,199
+1	88.1	94.03	+1	156.6	7,203
					7,208
0	0.0	93.98	0	0.0	7,283
					7,358
-1	(34.2)	93.89	-1	(156.6)	7,362
-2	(68.4)	93.80	-2	(313.2)	7,366
-3	(102.5)	93.71	-3	(469.8)	7,371
-4	(136.7)	93.61	-4	(626.4)	7,375
-5	(170.9)	93.52	-5	(783.0)	7,379
-6	(205.1)	93.43	-6	(939.6)	7,384
-7	(239.3)	93.34	-7	(1,096.3)	7,388
-8	(273.5)	93.24	-8	(1,252.9)	7,392
-9	(307.6)	93.15	-9	(1,409.5)	7,397
-10	(341.8)	93.06	-10	(1,566.1)	7,401
	Weighting Factor =	5.89%		Weighting Factor =	10.47%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2014 - DECEMBER 2014

BAYSIDE 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,296.6	87.9	+10	1,344.6	7,310
+9	1,166.9	87.7	+9	1,210.1	7,310
+8	1,037.2	87.5	+8	1,075.7	7,310
+7	907.6	87.3	+7	941.2	7,310
+6	777.9	87.0	+6	806.8	7,311
+5	648.3	86.8	+5	672.3	7,311
+4	518.6	86.6	+4	537.8	7,311
+3	389.0	86.4	+3	403.4	7,311
+2	259.3	86.2	+2	268.9	7,311
+1	129.7	86.0	+1	134.5	7,311
					7,312
0	0.0	85.8	0	0.0	7,387
					7,462
-1	(208.5)	85.4	-1	(134.5)	7,462
-2	(417.1)	84.9	-2	(268.9)	7,462
-3	(625.6)	84.5	-3	(403.4)	7,462
-4	(834.1)	84.1	-4	(537.8)	7,462
-5	(1,042.6)	83.7	-5	(672.3)	7,463
-6	(1,251.2)	83.3	-6	(806.8)	7,463
-7	(1,459.7)	82.8	-7	(941.2)	7,463
-8	(1,668.2)	82.4	-8	(1,075.7)	7,463
-9	(1,876.7)	82.0	-9	(1,210.1)	7,463
-10	(2,085.3)	81.6	-10	(1,344.6)	7,463
	Weighting Factor =	8.67%		Weighting Factor =	8.99%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	78.8	39.4	78.8	78.8	78.8	78.8	78.8	73.7	0.0	0.0	60.3	78.8	60.6
2. POF	0.0	50.0	0.0	0.0	0.0	0.0	0.0	6.5	100.0	100.0	23.4	0.0	23.0
3. EUOF	21.2	10.6	21.2	21.2	21.2	21.2	21.2	19.9	0.0	0.0	16.3	21.2	16.4
4. EUOR	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	0.0	0.0	21.2	21.2	21.2
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	609	275	609	590	609	590	609	570	0	0	452	609	5,522
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	135	397	134	130	135	130	135	174	720	744	269	135	3,238
9. POH	0	336	0	0	0	0	0	48	720	744	169	0	2,017
10. EFOH	153	69	153	148	153	148	153	143	0	0	114	153	1,390
11. EMOH	5	2	5	5	5	5	5	4	0	0	3	5	42
12. OPER BTU (GBTU)	2,336	1,015	2,361	2,256	2,341	2,271	2,351	2,203	0	0	1,702	2,321	21,157
13. NET GEN (MWH)	222,320	96,390	224,790	214,940	223,060	216,350	224,070	209,950	0	0	162,060	220,790	2,014,720
14. ANOHR (Btu/kwh)	10,509	10,526	10,504	10,498	10,495	10,495	10,493	10,493	0	0	10,505	10,512	10,501
15. NOF (%)	92.4	88.7	93.4	94.6	95.1	95.2	95.6	95.7	0.0	0.0	93.1	91.8	94.0
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF (	-4.808	) +	10,953									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	80.1	40.1	80.1	80.1	80.1	80.1	80.1	80.1	80.1	75.0	58.7	80.1	74.9
2. POF	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.5	26.8	0.0	6.6
3. EUOF	19.9	9.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	18.6	14.5	19.9	18.6
4. EUOR	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	625	282	625	605	625	605	625	625	605	585	444	625	6,876
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	119	390	118	115	119	115	119	119	115	159	277	119	1,884
9. POH	0	336	0	0	0	0	0	0	0	48	193	0	577
10. EFOH	116	52	116	112	116	112	116	116	112	109	82	116	1,278
11. EMOH	32	14	31	31	32	31	32	32	31	29	22	32	347
12. OPER BTU (GBTU)	2,313	999	2,325	2,235	2,336	2,261	2,331	2,342	2,263	2,189	1,608	2,307	25,514
13. NET GEN (MWH)	224,660	96,460	225,980	217,760	227,890	220,560	227,390	228,620	220,860	213,650	156,240	223,990	2,484,060
14. ANOHR (Btu/kwh)	10,298	10,355	10,291	10,265	10,249	10,249	10,252	10,245	10,248	10,247	10,292	10,301	10,271
15. NOF (%)	91.0	86.6	91.5	93.5	94.7	94.7	94.5	95.0	94.8	94.9	91.4	90.7	93.0
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF (	-13.110	) +	11,491									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	79.3	79.3	43.5	79.3	79.3	79.3	79.3	79.3	79.3	79.3	52.9	79.3	74.1
2. POF	0.0	0.0	45.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	20.7	20.7	11.4	20.7	20.7	20.7	20.7	20.7	20.7	20.7	13.8	20.7	19.4
4. EUOR	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	699	632	384	677	699	677	699	699	677	699	451	699	7,692
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	45	40	359	43	45	43	45	45	43	45	270	45	1,068
9. POH	0	0	335	0	0	0	0	0	0	0	240	0	575
10. EFOH	97	87	53	94	97	94	97	97	94	97	63	97	1,064
11. EMOH	57	52	32	56	57	56	57	57	56	57	37	57	632
12. OPER BTU (GBTU)	2,193	1,998	1,205	2,163	2,254	2,190	2,268	2,270	2,209	2,262	1,438	2,196	24,649
13. NET GEN (MWH)	203,990	186,220	112,130	202,100	211,080	205,190	212,740	212,930	207,490	211,940	134,300	204,350	2,304,460
14. ANOHR (Btu/kwh)	10,752	10,731	10,750	10,704	10,679	10,671	10,663	10,661	10,647	10,671	10,709	10,748	10,696
15. NOF (%)	80.0	80.7	80.0	81.8	82.7	83.0	83.4	83.5	84.0	83.1	81.6	80.1	82.1
16. NPC (MW)	365	365	365	365	365	365	365	365	365	365	365	365	365
17. ANOHR EQUATION	ANOHR = NOF (	-25.960	) +	12,827									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	76.5	76.5	69.0	0.0	19.7	76.5	76.5	76.5	76.5	76.5	76.5	51.8	62.6
2. POF	0.0	0.0	9.7	100.0	74.2	0.0	0.0	0.0	0.0	0.0	0.0	32.3	18.1
3. EUOF	23.5	23.5	21.3	0.0	6.1	23.5	23.5	23.5	23.5	23.5	23.5	15.9	19.3
4. EUOR	23.5	23.5	23.5	0.0	23.5	23.5	23.5	23.5	23.5	23.5	23.5	23.5	23.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	634	573	573	0	164	614	634	634	614	634	614	430	6,118
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	110	99	170	720	580	106	110	110	106	110	107	314	2,642
9. POH	0	0	72	720	552	0	0	0	0	0	0	240	1,584
10. EFOH	149	135	134	0	38	144	149	149	144	149	144	101	1,438
11. EMOH	26	24	24	0	7	25	26	26	25	26	25	18	252
12. OPER BTU (GBTU)	2,365	2,129	2,162	0	610	2,324	2,399	2,405	2,332	2,400	2,297	1,595	23,016
13. NET GEN (MWH)	226,790	204,090	207,740	0	58,670	224,460	231,690	232,380	225,340	231,750	221,310	152,790	2,217,010
14. ANOHR (Btu/kwh)	10,427	10,433	10,406	11,953	10,389	10,355	10,355	10,351	10,348	10,355	10,377	10,437	10,381
15. NOF (%)	85.8	85.4	86.9	0.0	87.9	89.8	89.8	90.1	90.2	89.8	88.6	85.2	88.3
16. NPC (MW)	417	417	417	407	407	407	407	407	407	407	407	417	410
17. ANOHR EQUATION	ANOHR = NOF (	-17.797	) +	11,953									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	88.6	88.6	48.6	88.6	88.6	88.6	88.6	88.6	88.6	88.6	73.8	88.6	84.0
2. POF	0.0	0.0	45.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.6	0.0	5.2
3. EUOF	11.4	11.4	6.3	11.4	11.4	11.4	11.4	11.4	11.4	11.4	9.5	11.4	10.8
4. EUOR	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	682	616	374	671	699	678	711	701	678	698	567	702	7,777
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	62	56	369	49	45	42	33	43	42	46	154	42	983
9. POH	0	0	335	0	0	0	0	0	0	0	120	0	455
10. EFOH	59	53	32	57	59	57	59	59	57	59	47	59	656
11. EMOH	26	24	14	25	26	25	26	26	25	26	21	26	292
12. OPER BTU (GBTU)	1,521	1,374	834	1,498	1,560	1,513	1,585	1,563	1,512	1,557	1,265	1,567	17,348
13. NET GEN (MWH)	144,990	130,960	79,510	141,990	148,270	143,810	151,180	149,020	144,250	148,380	120,430	148,380	1,651,170
14. ANOHR (Btu/kwh)	10,489	10,489	10,490	10,549	10,518	10,519	10,487	10,490	10,480	10,490	10,501	10,563	10,506
15. NOF (%)	96.6	96.6	96.6	96.2	96.4	96.4	96.7	96.6	96.7	96.6	96.5	96.1	96.5
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF (	-132.175	) +	23,262									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	98.9	98.9	70.1	98.9	98.9	98.9	98.9	98.9	98.9	98.9	98.9	70.2	94.0
2. POF	0.0	0.0	29.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.0	4.9
3. EUOF	1.1	1.1	0.8	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.8	1.1
4. EUOR	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	560	604	483	573	675	691	713	710	712	656	530	482	7,389
7. RSH	175	60	38	139	60	21	22	25	0	79	183	40	844
8. UH	9	8	222	8	9	8	9	9	8	9	8	222	527
9. POH	0	0	216	0	0	0	0	0	0	0	0	216	432
10. EFOH	2	1	1	2	2	2	2	2	2	2	2	1	18
11. EMOH	7	6	5	7	7	7	7	7	7	7	7	5	77
12. OPER BTU (GBTU)	1,795	2,437	1,781	1,446	2,013	2,166	2,227	2,147	2,429	2,062	1,721	1,522	23,770
13. NET GEN (MWH)	244,970	338,820	245,690	195,890	275,700	297,780	306,050	294,340	336,360	283,510	237,330	207,470	3,263,910
14. ANOHR (Btu/kwh)	7,328	7,192	7,249	7,384	7,301	7,273	7,276	7,294	7,222	7,272	7,252	7,335	7,283
15. NOF (%)	55.2	70.8	64.2	48.8	58.3	61.5	61.2	59.1	67.4	61.7	63.9	54.3	60.4
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF (	-8.710	) +	7,809									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2014 - DECEMBER 2014

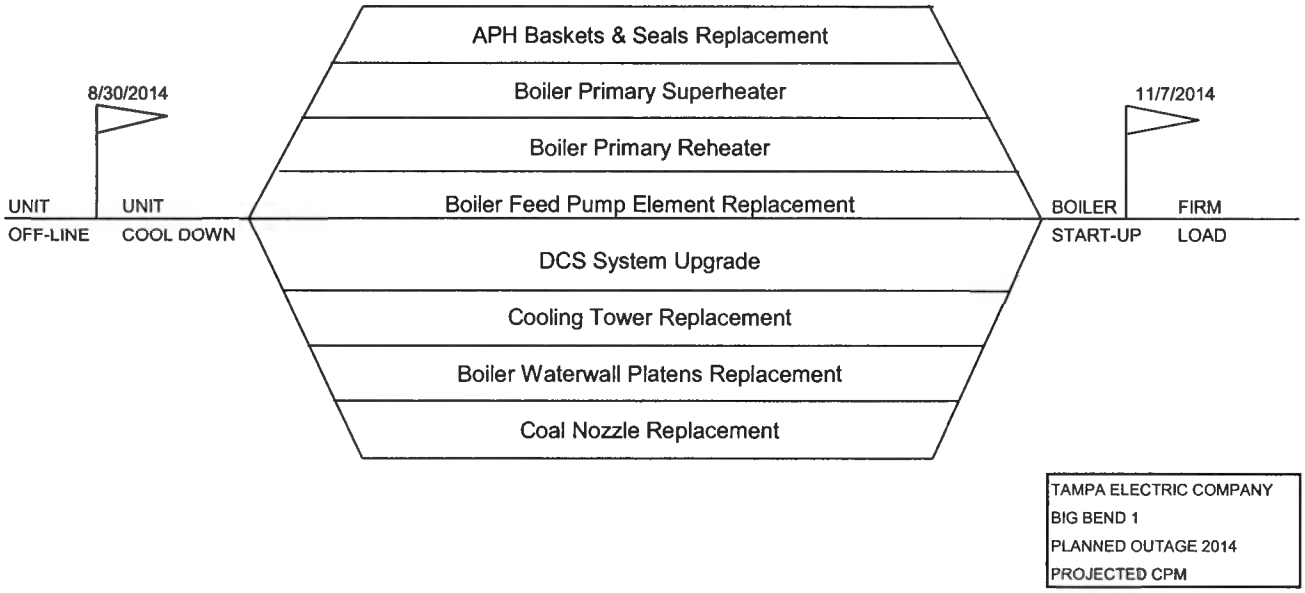
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014
1. EAF (%)	90.2	61.2	90.2	90.2	90.2	90.2	90.2	90.2	90.2	90.2	63.2	90.2	85.8
2. POF	0.0	32.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	4.9
3. EUOF	9.8	6.6	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	6.8	9.8	9.3
4. EUOR	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	671	411	670	650	671	650	671	671	650	671	456	671	7,514
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	73	261	73	70	73	70	73	73	70	73	265	73	1,246
9. POH	0	216	0	0	0	0	0	0	0	0	216	0	432
10. EFOH	61	38	61	59	61	59	61	61	59	61	42	61	687
11. EMOH	11	7	11	11	11	11	11	11	11	11	8	11	127
12. OPER BTU (GBTU)	1,409	1,553	1,950	2,929	3,303	3,225	3,360	3,429	3,631	3,370	1,867	1,562	31,771
13. NET GEN (MWH)	185,470	208,380	259,090	398,990	452,410	441,980	460,760	470,820	501,940	462,170	252,930	206,200	4,301,140
14. ANOHR (Btu/kwh)	7,595	7,455	7,528	7,342	7,301	7,297	7,293	7,282	7,234	7,291	7,383	7,576	7,387
15. NOF (%)	26.4	48.4	36.9	66.1	72.5	73.2	73.9	75.5	83.2	74.1	59.7	29.3	59.1
16. NPC (MW)	1,047	1,047	1,047	929	929	929	929	929	929	929	929	1,047	968
17. ANOHR EQUATION	ANOHR = NOF (		-6.365	) +		7,763							

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2014 - DECEMBER 2014

	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
+	BIG BEND 1	Feb 02 - Feb 15	Fuel System Cleanup and FGD/SCR work
		Aug 30 - Nov 07	APH Baskets & Seals Replacement, Boiler Feed Pump Turbine Blade, Coal Nozzle Replacement, Boiler Feed Pump Element Replacement, DCS System Upgrade, Cooling Tower Replacement, High Temp SH Dissimilar Metal Weld, Boiler Primary Reheater Replacement, Boiler Primary Superheater Replacement, Boiler Waterwall Platens Replacement
	BIG BEND 2	Feb 01 - Feb 14	Fuel System Cleanup and FGD/SCR work
		Oct 30 - Nov 08	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Mar 01 - Mar 14	Fuel System Cleanup and FGD/SCR work
		Nov 15 - Nov 24	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 4	Mar 29 - May 23	Air Heater Rotor & Element, Boiler Feed Pump Element, Bunker Liners, Burner Assembly & Coal Nozzles, Coal Feeder Replacement, Cooling Tower Replacement, DCS Upgrades, EH5 & EH6 Replacement, FGD C Booster Fan, FGD Tower Lined Piping, Finishing Reheater Replacement, BFP Turbine Overhaul, HP/IP/LP Turbine work, Precipitator work, Circulating Water Discharge Outfall Structure
		Dec 06 - Dec 15	Fuel System Cleanup and FGD/SCR work
	POLK 1	Mar 02 - Mar 15	Gasifier & Power Block Outage
		Nov 09 - Nov 13	Gasifier Outage
	BAYSIDE 1	Mar 17 - Mar 25	Fuel System Cleanup
		Dec 02 - Dec 10	Fuel System Cleanup
	BAYSIDE 2	Feb 19 - Feb 27	Fuel System Cleanup
		Nov 15 - Nov 23	Fuel System Cleanup

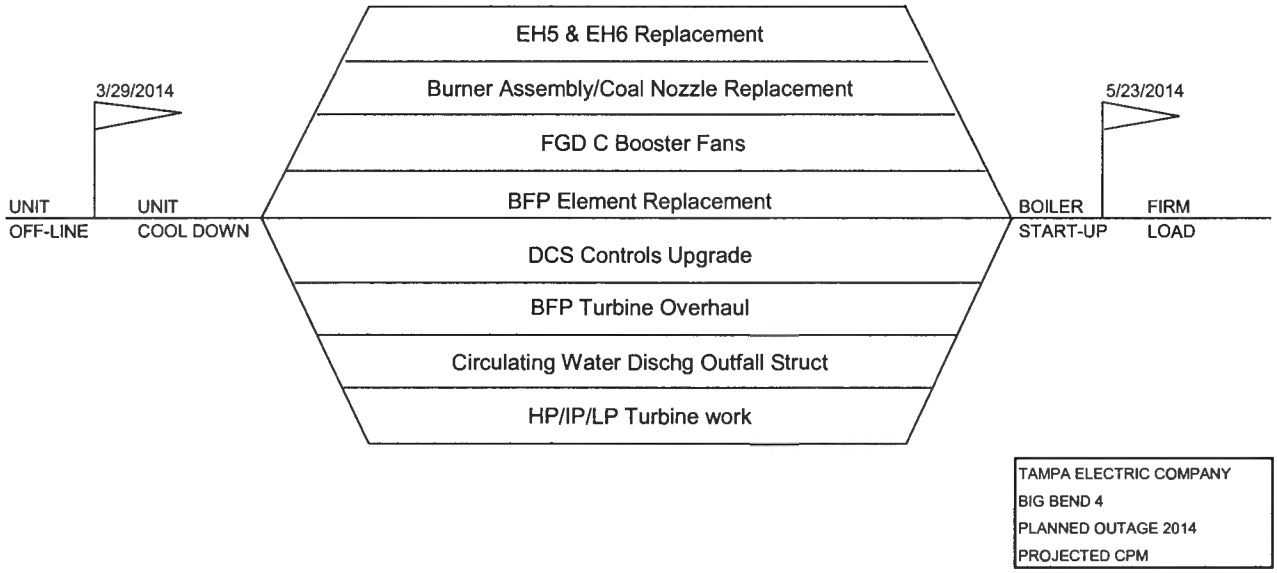
+ **These units have CPM included. CPM for units with less than or equal to 4 weeks are not included.**

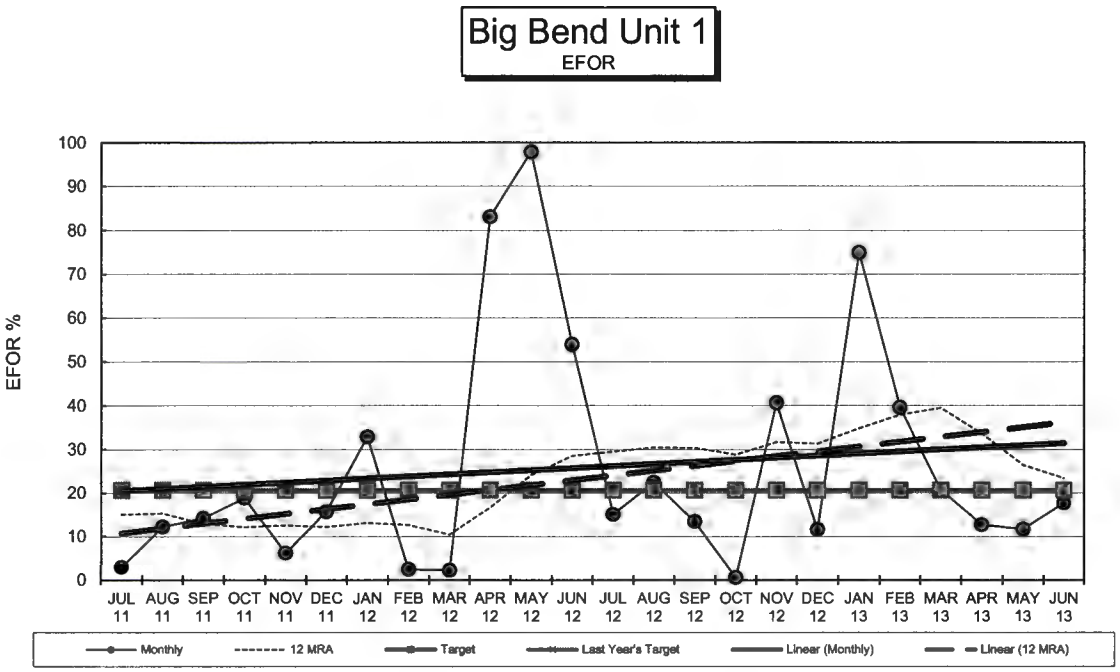
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2014 - DECEMBER 2014



TAMPA ELECTRIC COMPANY
BIG BEND 1
PLANNED OUTAGE 2014
PROJECTED CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2014 - DECEMBER 2014




Big Bend Unit 1
EFOR
EFOR %
100
90
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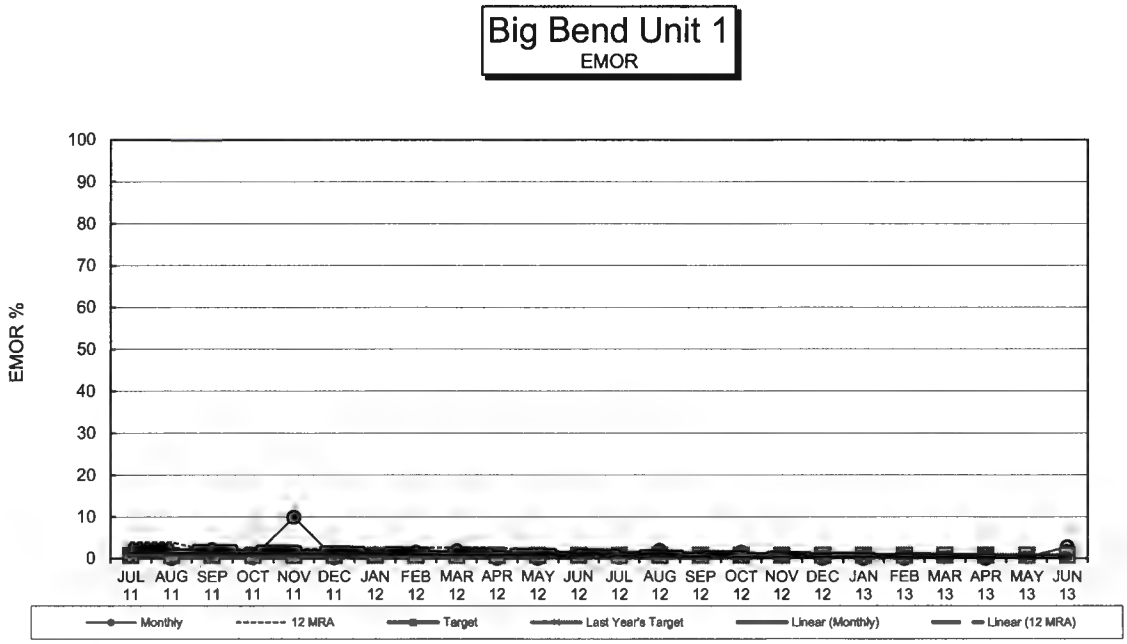
JUL 11 AUG 11 SEP 11 OCT 11 NOV 11 DEC 11 JAN 12 FEB 12 MAR 12 APR 12 MAY 12 JUN 12 JUL 12 AUG 12 SEP 12 OCT 12 NOV 12 DEC 12 JAN 13 FEB 13 MAR 13 APR 13 MAY 13 JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 1
EMOR
EMOR %
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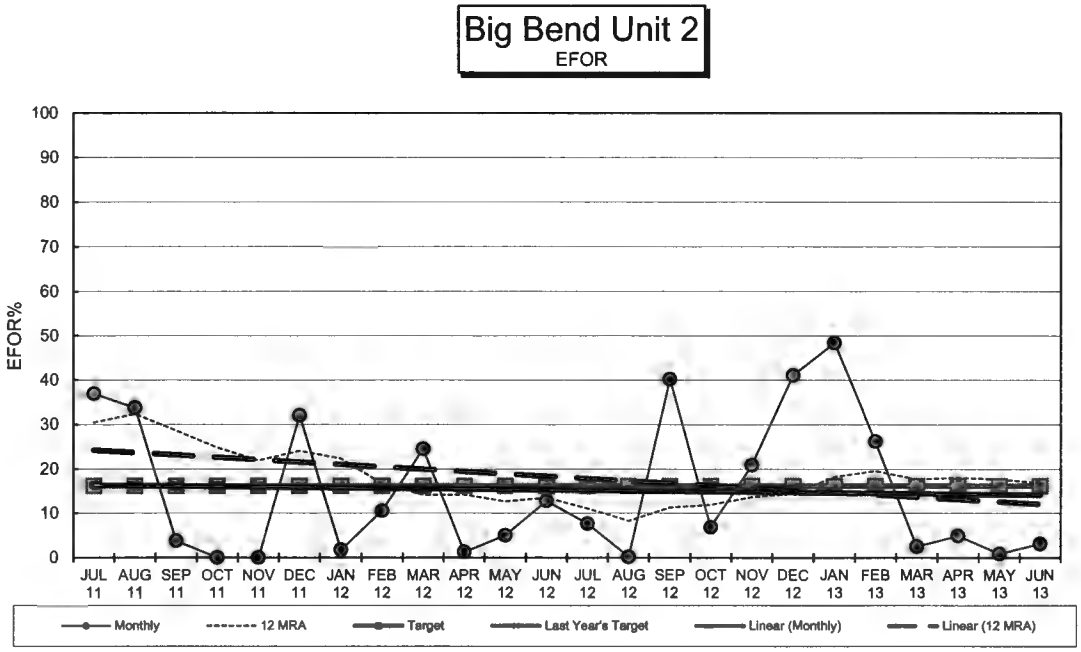
JUL 11 AUG 11 SEP 11 OCT 11 NOV 11 DEC 11 JAN 12 FEB 12 MAR 12 APR 12 MAY 12 JUN 12 JUL 12 AUG 12 SEP 12 OCT 12 NOV 12 DEC 12 JAN 13 FEB 13 MAR 13 APR 13 MAY 13 JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)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EFOR%
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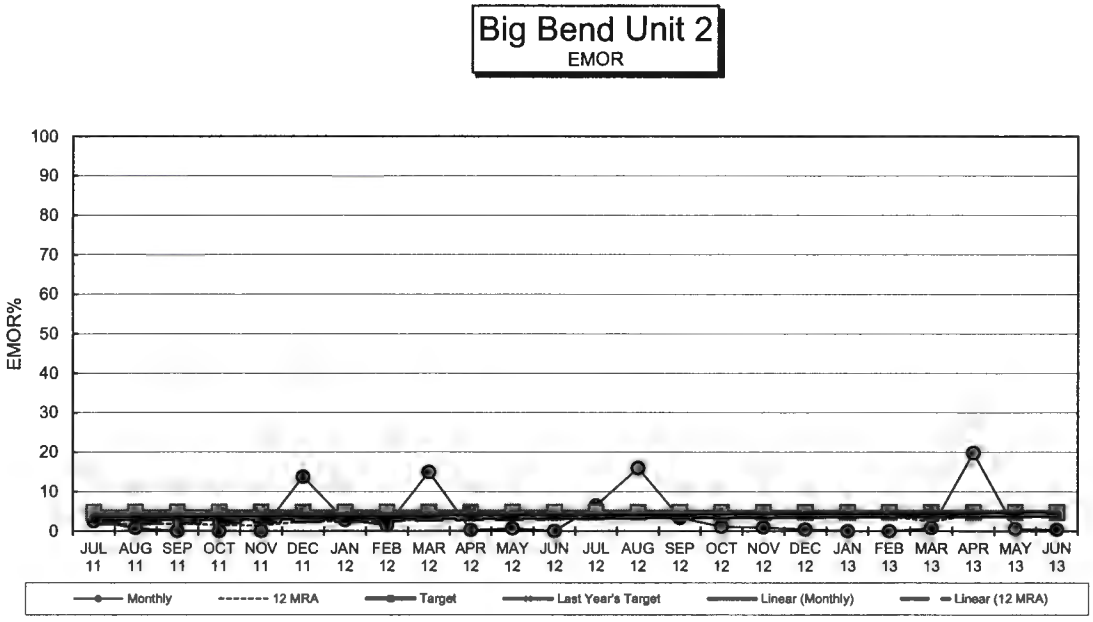
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 2
EMOR
EMOR%
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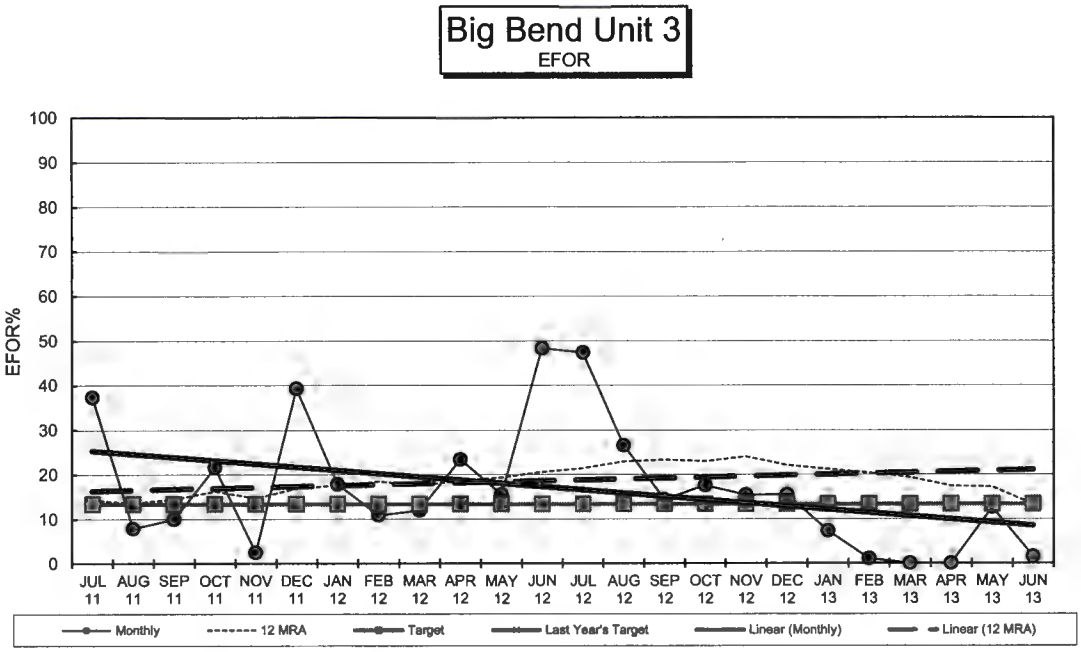
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 3
EFOR
EFOR%
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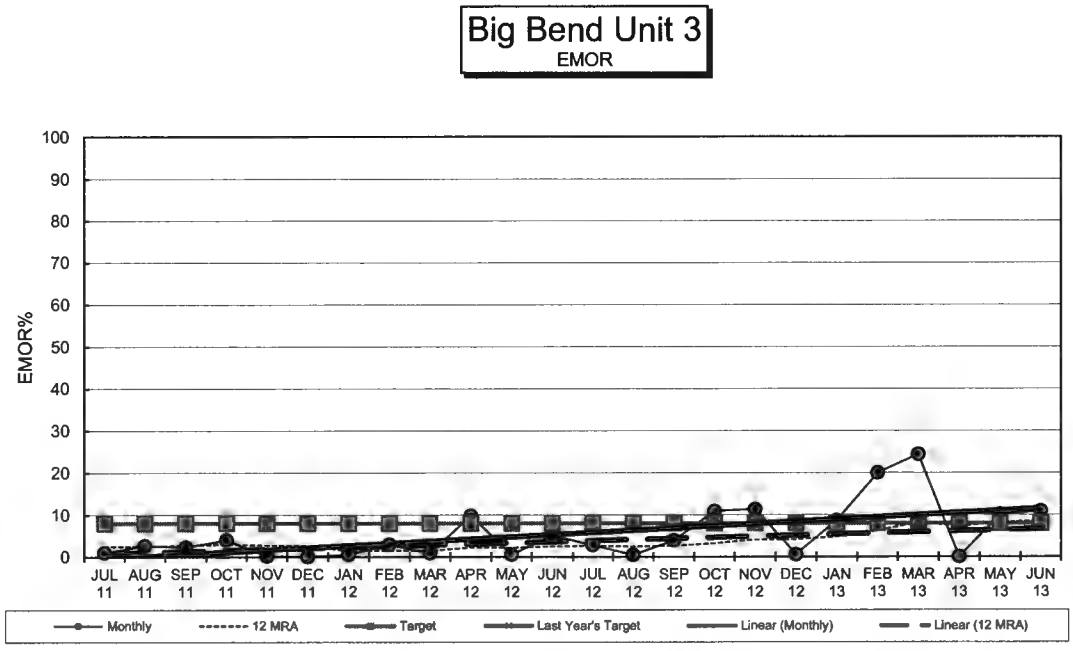
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 3
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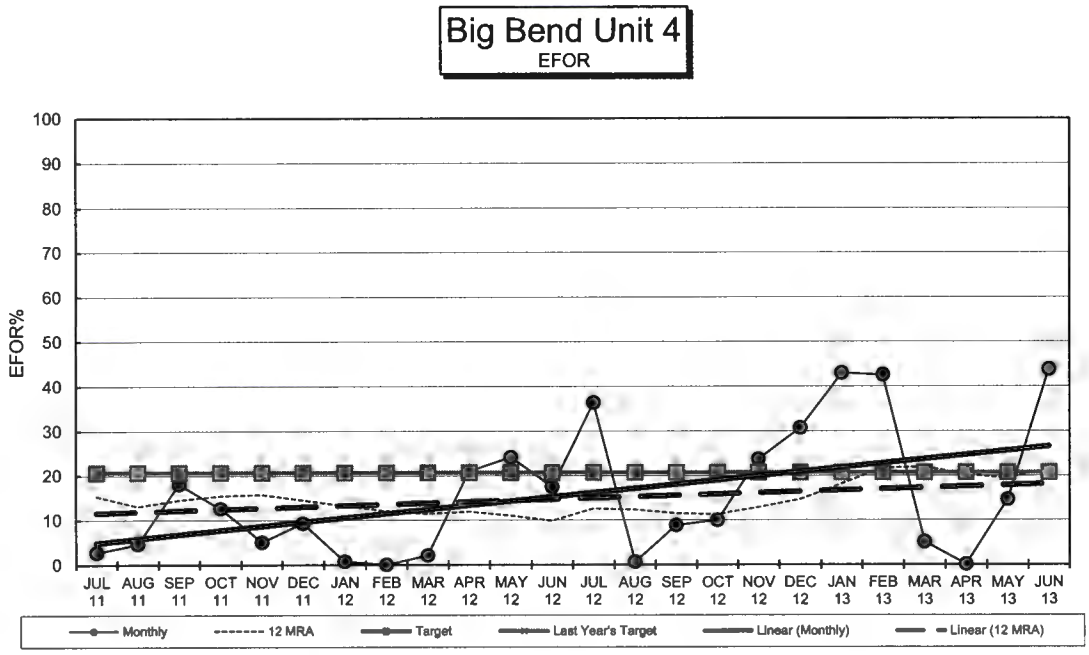
JUL 11 AUG 11 SEP 11 OCT 11 NOV 11 DEC 11 JAN 12 FEB 12 MAR 12 APR 12 MAY 12 JUN 12 JUL 12 AUG 12 SEP 12 OCT 12 NOV 12 DEC 12 JAN 13 FEB 13 MAR 13 APR 13 MAY 13 JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EFOR
EFOR%
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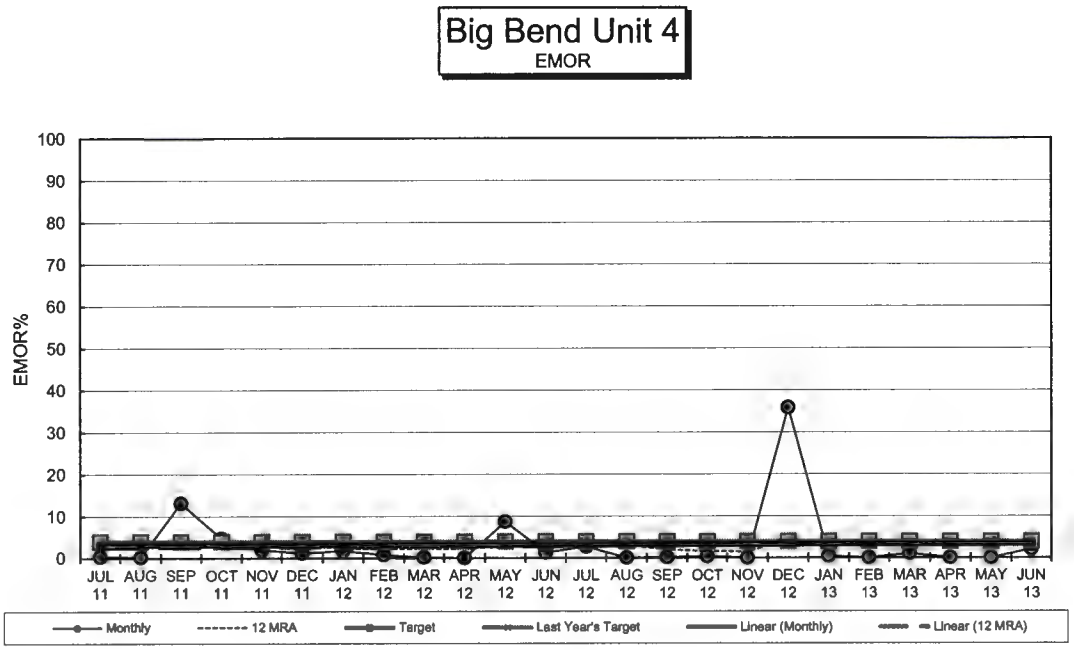
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Big Bend Unit 4
EMOR
EMOR%
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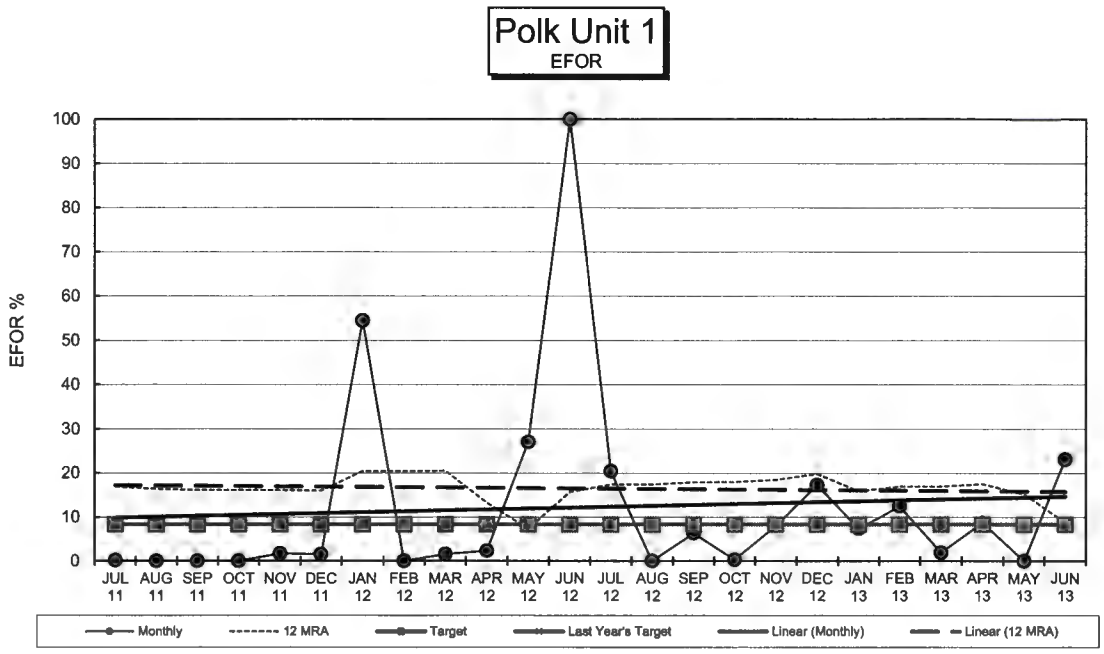
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EFOR
EFOR %
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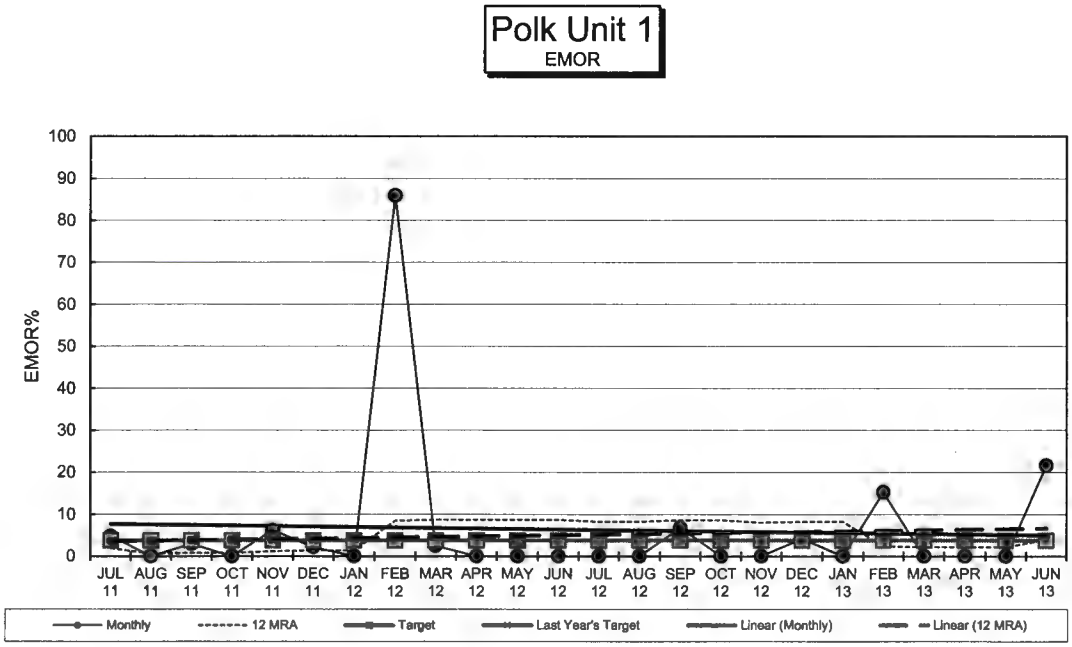
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Polk Unit 1
EMOR
EMOR%
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JUL 11 AUG 11 SEP 11 OCT 11 NOV 11 DEC 11 JAN 12 FEB 12 MAR 12 APR 12 MAY 12 JUN 12 JUL 12 AUG 12 SEP 12 OCT 12 NOV 12 DEC 12 JAN 13 FEB 13 MAR 13 APR 13 MAY 13 JUN 13
Monthly
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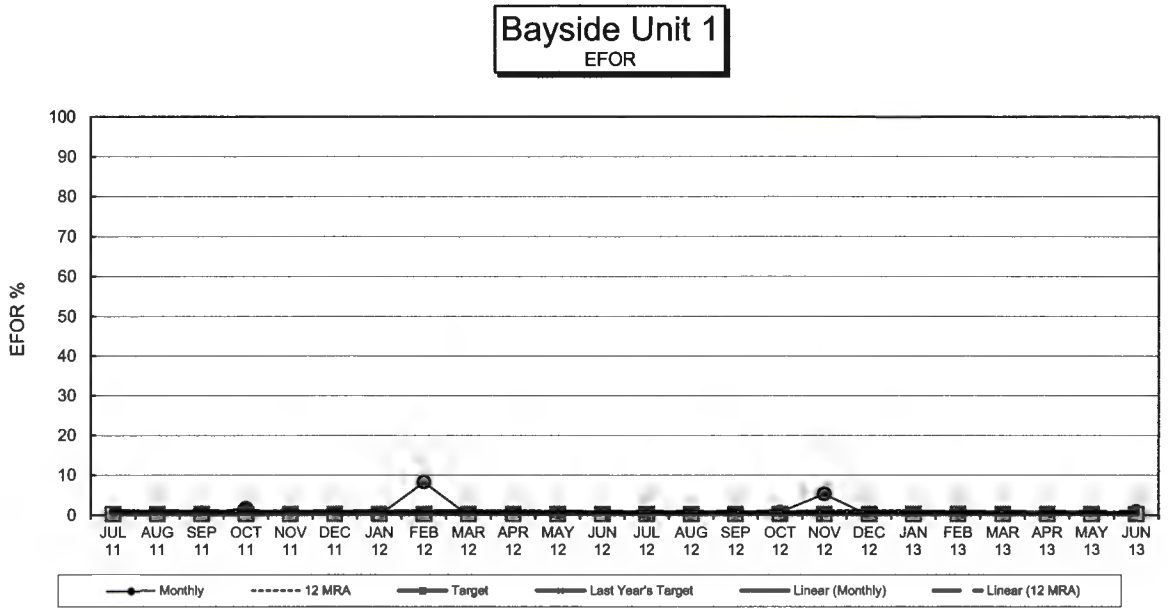
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EFOR
EFOR %
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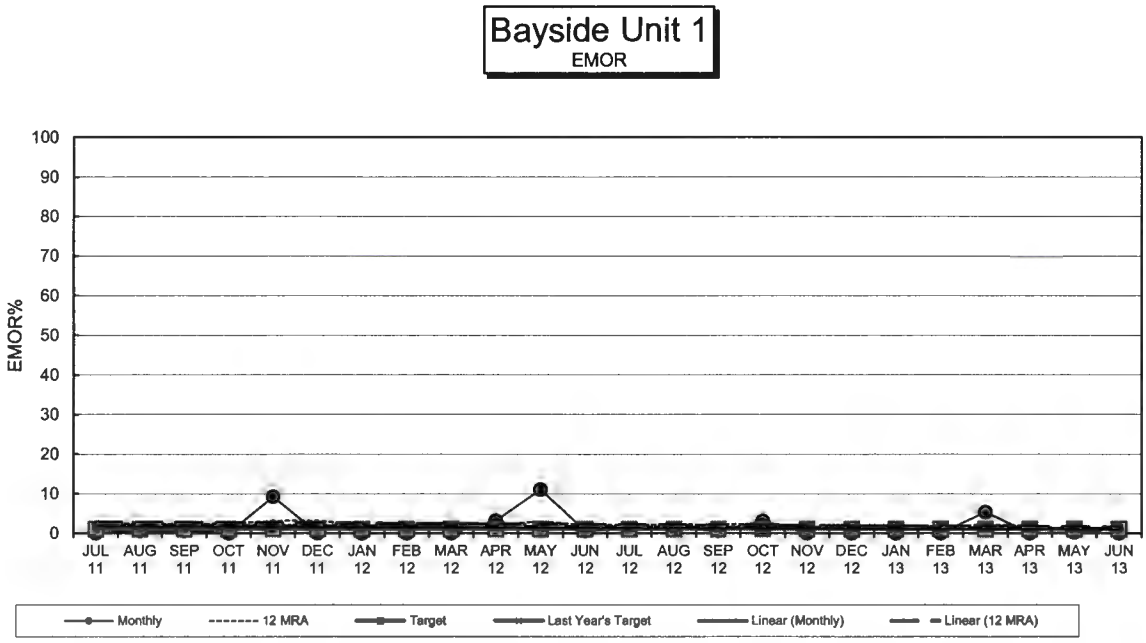
JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
JAN 12
FEB 12
MAR 12
APR 12
MAY 12
JUN 12
JUL 12
AUG 12
SEP 12
OCT 12
NOV 12
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 1
EMOR
EMOR%
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NOV 12
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Monthly
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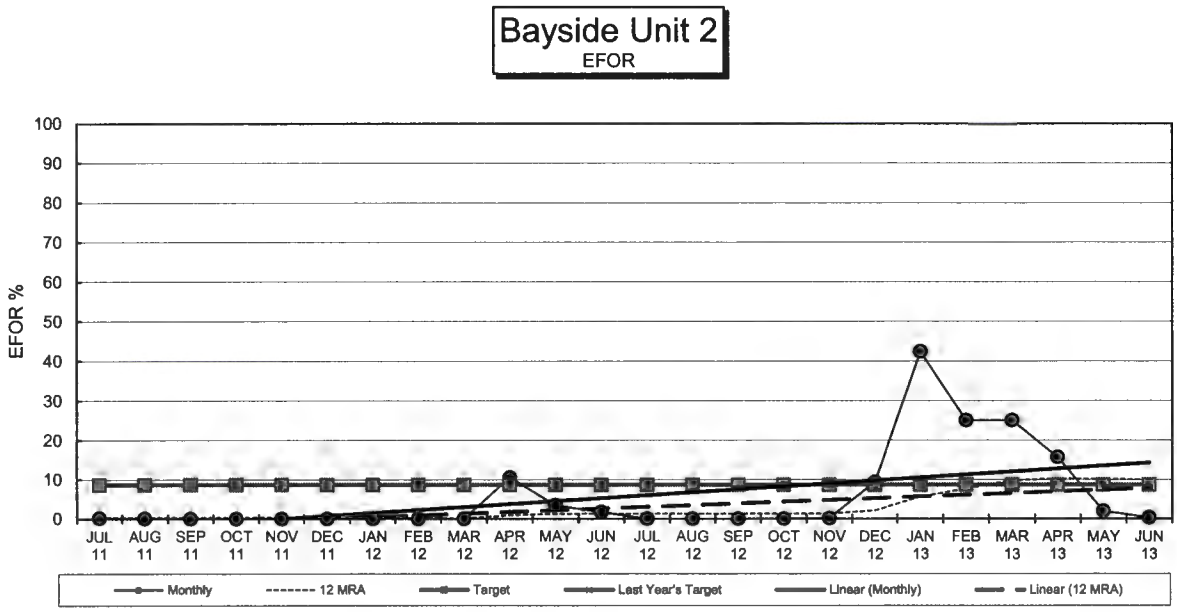
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EFOR
EFOR %
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JUL 11
AUG 11
SEP 11
OCT 11
NOV 11
DEC 11
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OCT 12
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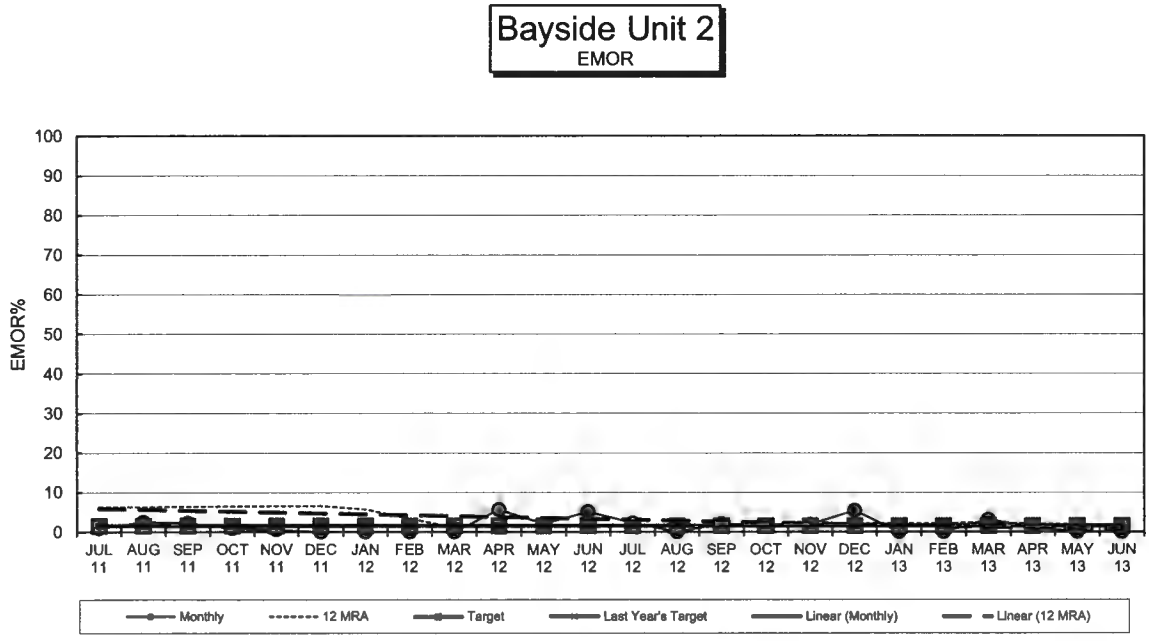
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)


Bayside Unit 2
EMOR
EMOR%
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JUL 11
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SEP 11
OCT 11
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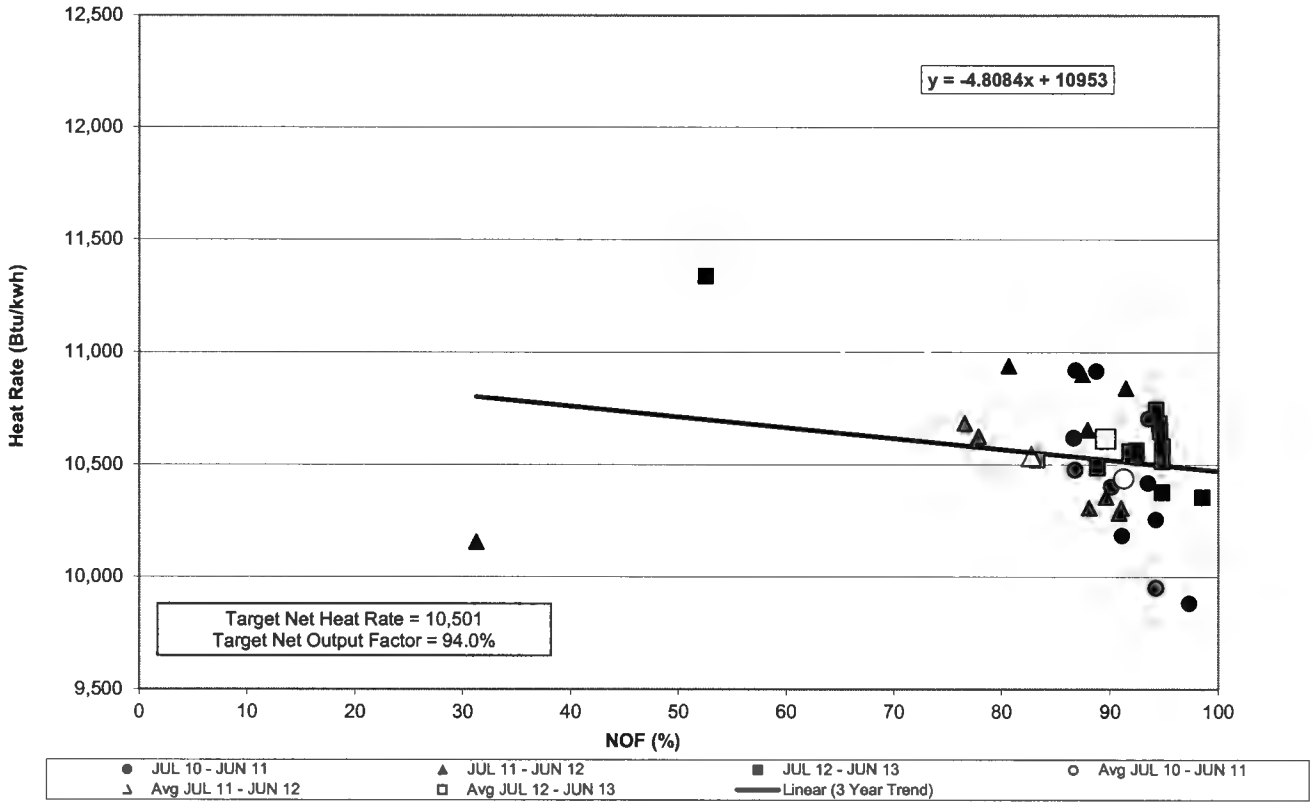
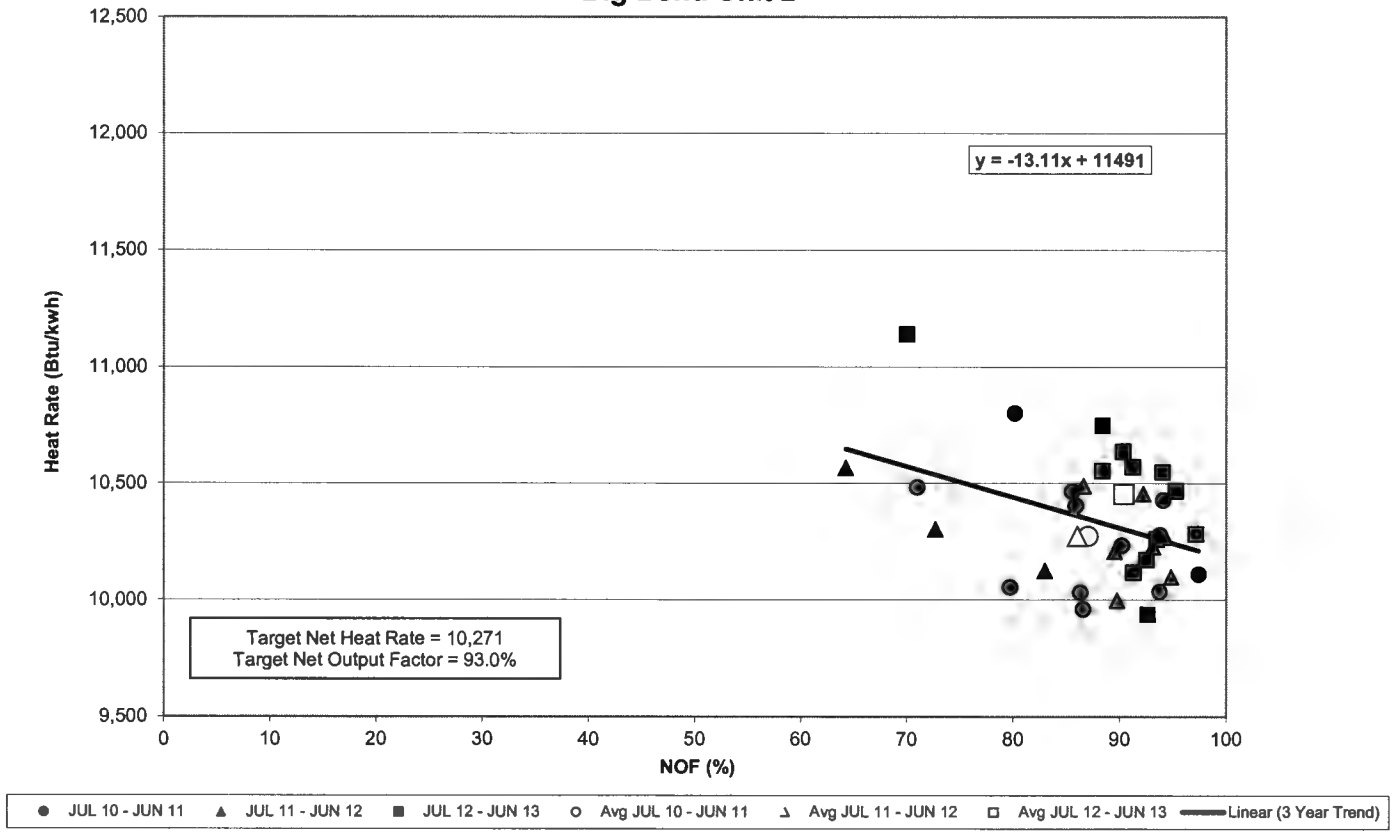
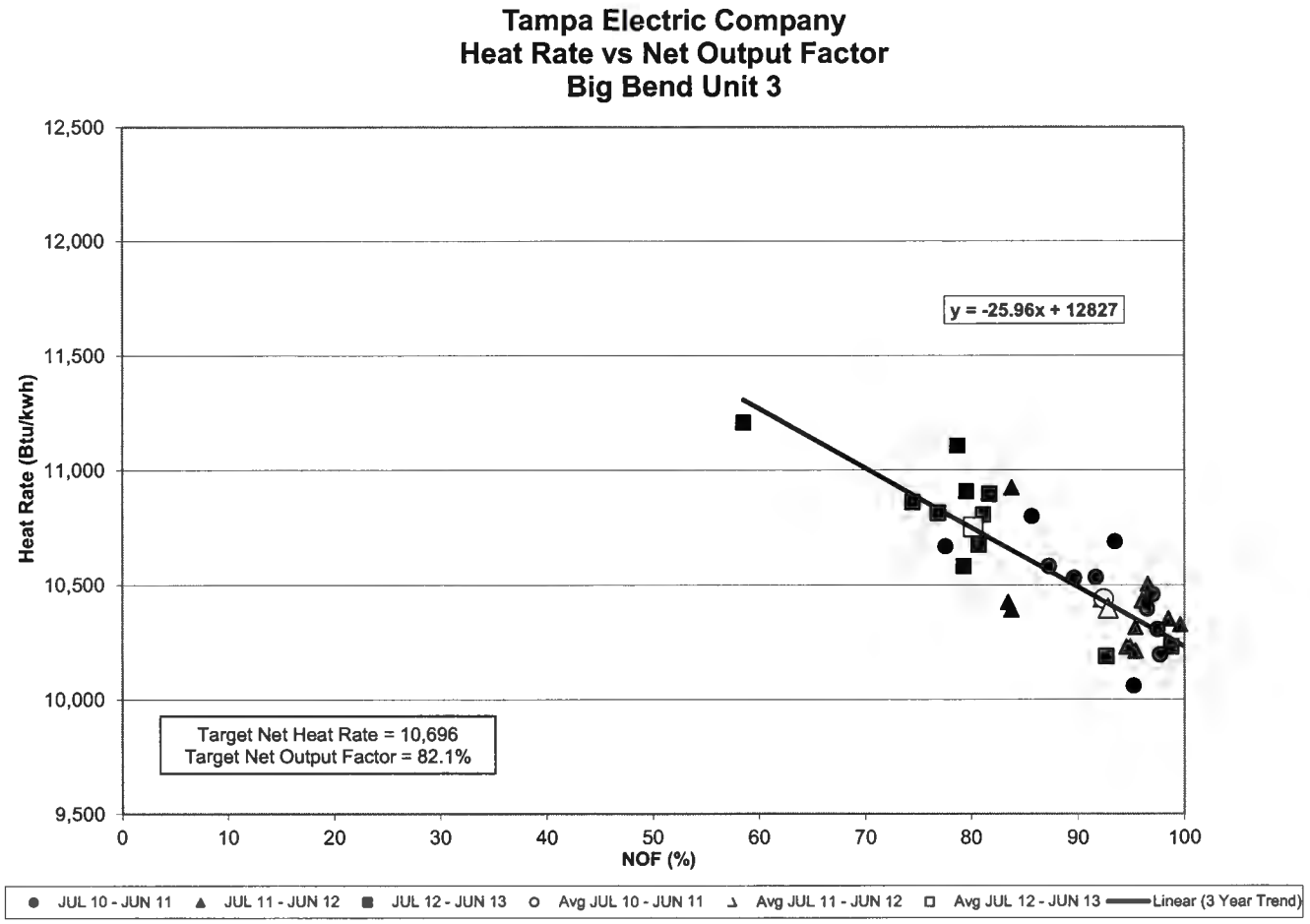
DEC 12
JAN 13
FEB 13
MAR 13
APR 13
MAY 13
JUN 13
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1

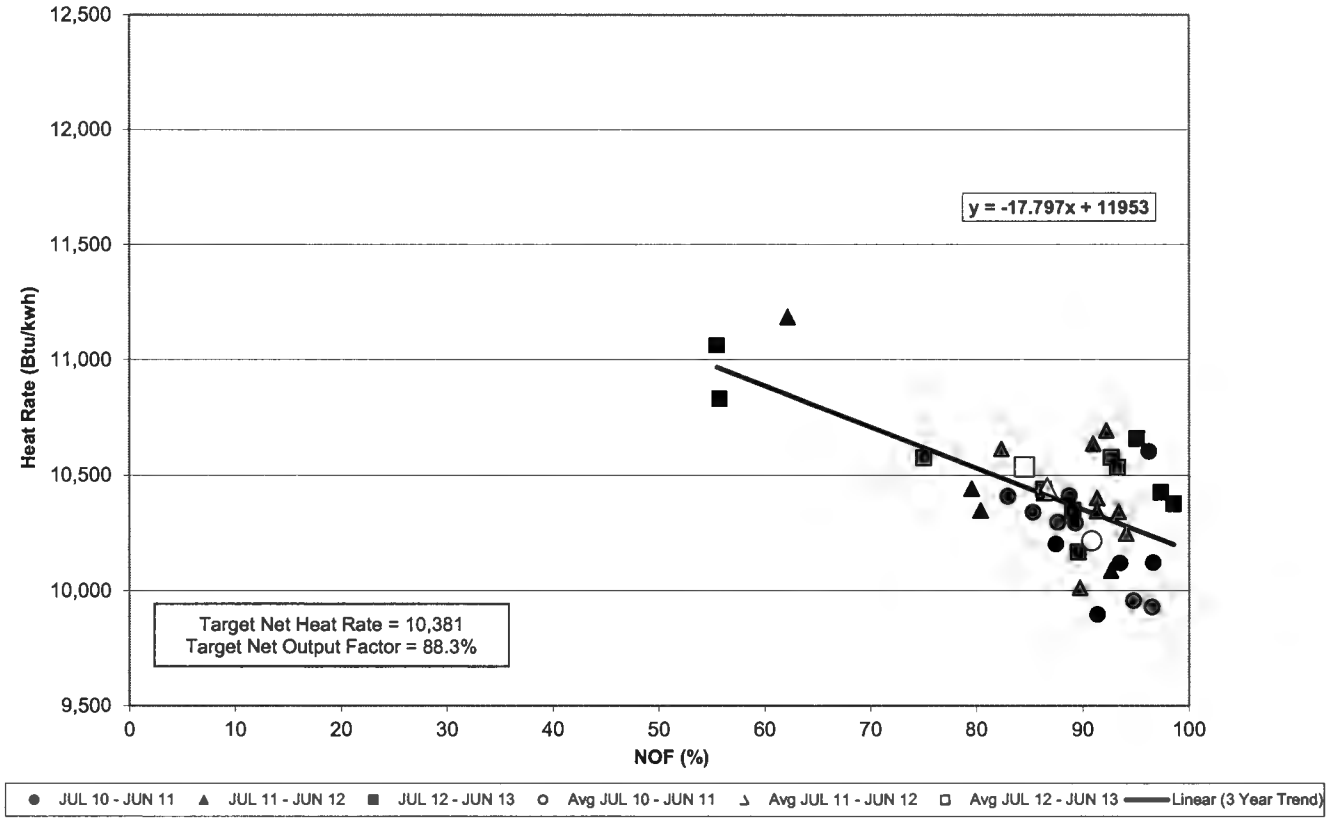


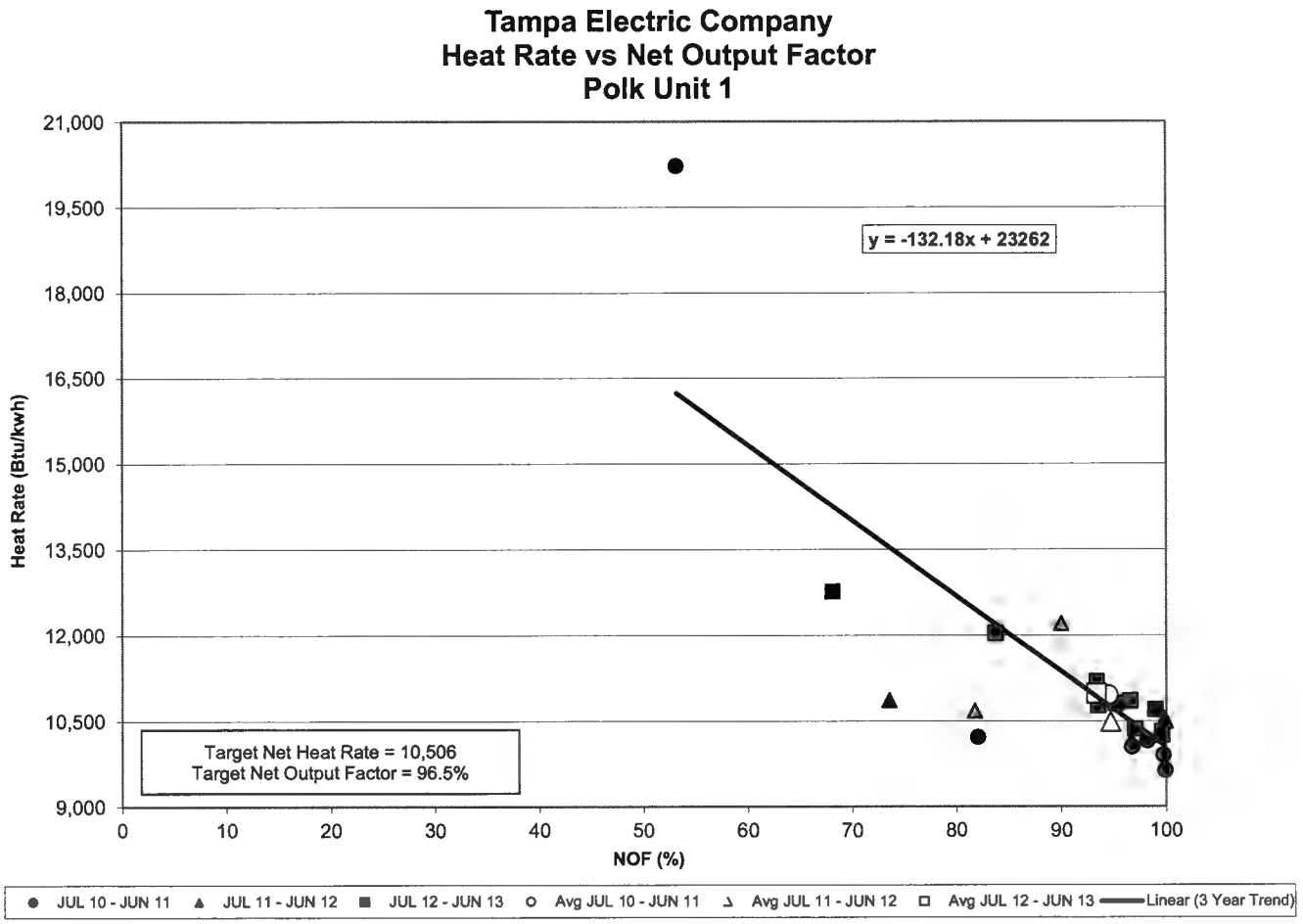
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2



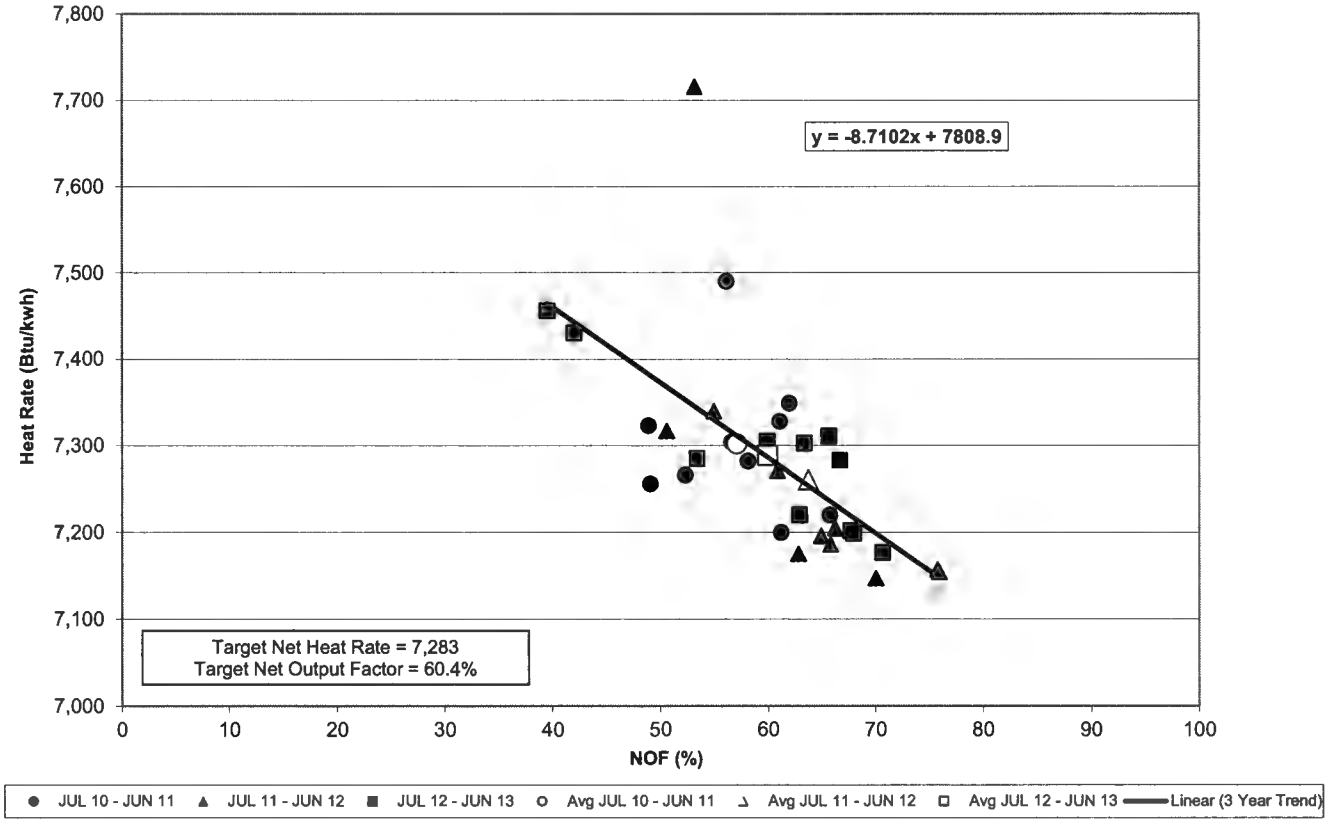

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3
Heat Rate (Btu/kwh)
12,500
12,000
11,500
11,000
10,500
10,000
9,500
0
10
20
30
40
50
60
70
80
90
100
NOF (%)
y = -25.96x + 12827
Target Net Heat Rate = 10,696
Target Net Output Factor = 82.1%
JUL 10 - JUN 11
JUL 11 - JUN 12
JUL 12 - JUN 13
Avg JUL 10 - JUN 11
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Linear (3 Year Trend)

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4

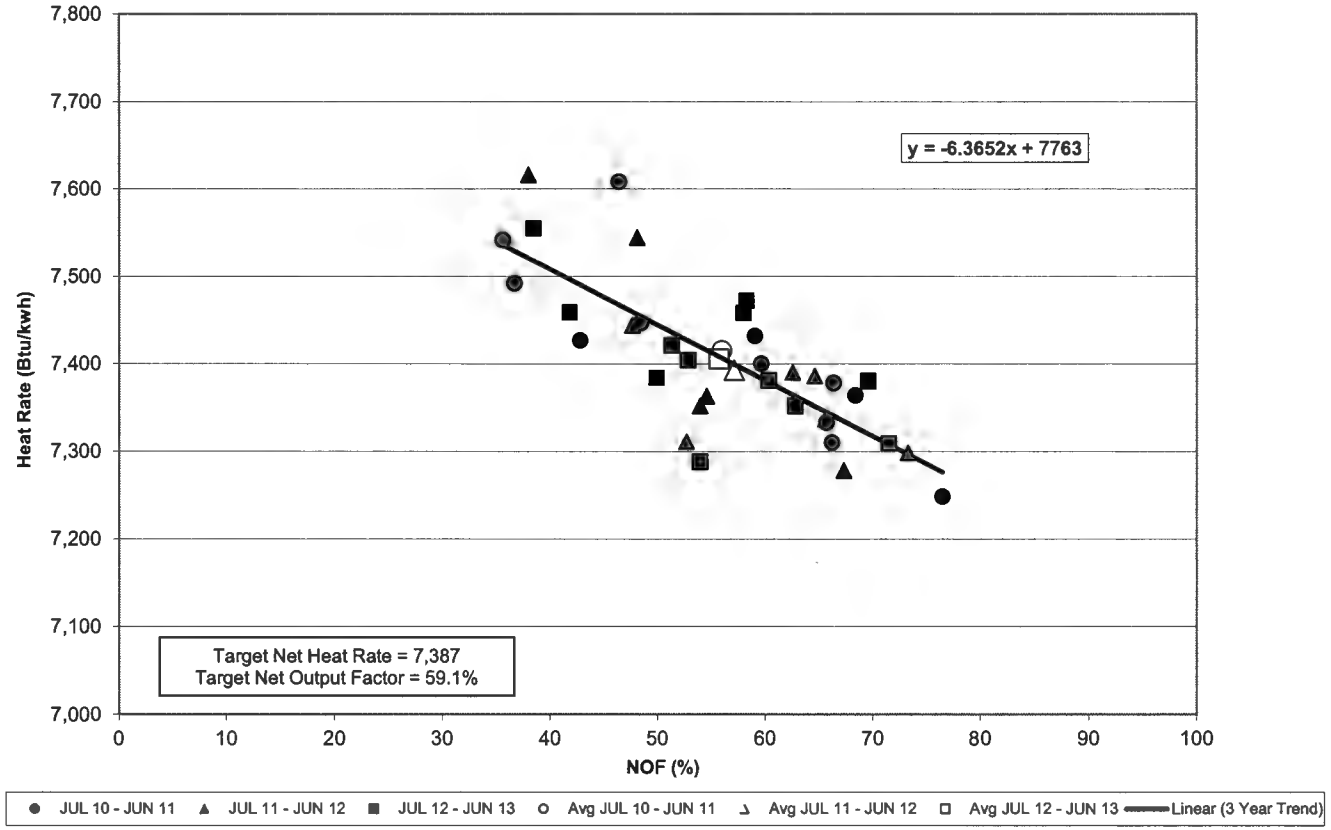



Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1
y = -132.18x + 23262
Target Net Heat Rate = 10,506
Target Net Output Factor = 96.5%
Heat Rate (Btu/kwh)
NOF (%)
21,000
19,500
18,000
16,500
15,000
13,500
12,000
10,500
9,000
0
10
20
30
40
50
60
70
80
90
100
JUL 10 - JUN 11
JUL 11 - JUN 12
JUL 12 - JUN 13
Avg JUL 10 - JUN 11
Avg JUL 11 - JUN 12
Avg JUL 12 - JUN 13
Linear (3 Year Trend)

Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1



Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2014 - DECEMBER 2014

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		443	410
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,670	3,472
	SYSTEM TOTAL	**4,614**	**4,407**
	% OF SYSTEM TOTAL	**79.5%**	**78.8%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2014 - DECEMBER 2014

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BAYSIDE 1		740	731
BAYSIDE 2		979	968
BAYSIDE 3		59	58
BAYSIDE 4		59	58
BAYSIDE 5		59	58
BAYSIDE 6		59	58
	BAYSIDE TOTAL	1,954	1,930
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		390	365
BIG BEND 4		443	410
	BIG BEND COAL TOTAL	1,660	1,552
BIG BEND CT4		59	58
	BIG BEND CT TOTAL	59	58
POLK 1		290	220
POLK 2		163	162
POLK 3		163	162
POLK 4		163	162
POLK 5		163	162
	POLK TOTAL	941	867
	SYSTEM TOTAL	**4,614**	**4,407**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2014 - DECEMBER 2014

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,301,140	23.07%	23.07%
BAYSIDE	1	3,263,910	17.51%	40.58%
BIG BEND	2	2,484,060	13.33%	53.91%
BIG BEND	3	2,304,460	12.36%	66.27%
BIG BEND	4	2,217,010	11.89%	78.16%
BIG BEND	1	2,014,720	10.81%	88.97%
POLK	1	1,651,170	8.86%	97.83%
POLK	2	136,480	0.73%	98.56%
POLK	3	81,470	0.44%	99.00%
POLK	4	62,790	0.34%	99.34%
POLK	5	37,870	0.20%	99.54%
BIG BEND CT	4	30,170	0.16%	99.70%
BAYSIDE	5	21,850	0.12%	99.82%
BAYSIDE	6	18,330	0.10%	99.92%
BAYSIDE	3	10,750	0.06%	99.97%
BAYSIDE	4	4,920	0.03%	100.00%
TOTAL GENERATION		18,641,100	100.00%	

GENERATION BY COAL UNITS: 10,671,420 MWH
% GENERATION BY COAL UNITS 57.25%

GENERATION BY NATURAL GAS UNITS: 7,969,680 MWH
% GENERATION BY NATURAL GAS UNITS: 42.75%

GENERATION BY OIL UNITS: - MWH
% GENERATION BY OIL UNITS: 0.00%

GENERATION BY GPIF UNITS: 18,236,470 MWH
% GENERATION BY GPIF UNITS: 97.83%

DOCKET NO. 130001-EI
GPIF 2014 PROJECTION FILING
EXHIBIT NO. ____ (BSB-2)
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

JANUARY 2014 - DECEMBER 2014

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2014 - DECEMBER 2014

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	60.6	23.0	16.4	10,501
Big Bend 2[2]	74.9	6.6	18.6	10,271
Big Bend 3[3]	74.1	6.6	19.4	10,696
Big Bend 4[4]	62.6	18.1	19.3	10,381
Polk 1[5]	84.0	5.2	10.8	10,506
Bayside 1[6]	94.0	4.9	1.1	7,283
Bayside 2[7]	85.8	4.9	9.3	7,387

1 Original Sheet 8.401.14E, Page 14

2 Original Sheet 8.401.14E, Page 15

3 Original Sheet 8.401.14E, Page 16

4 Original Sheet 8.401.14E, Page 17

5 Original Sheet 8.401.14E, Page 18

6 Original Sheet 8.401.14E, Page 19

7 Original Sheet 8.401.14E, Page 20

J. BRENT CALDWELL

EXHIBIT

2012 HEDGING ACTIVITY TRUE-UP

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 51
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Brent Caldwell - JBC-1

Tampa Electric
2012 Hedging Activity True-up

Tampa Electric's Risk Management Plan identified the following objectives:

- Qualitative Objectives
  Tampa Electric's primary goal in managing risk associated with fuel or power purchases focuses on minimizing supply risk to ensure reliability of electric service to its customers at a reasonable price. To the extent that price risk can be mitigated without compromising supply reliability or imposing unreasonable costs on its customers, Tampa Electric is committed to executing strategies to accomplish its risk management goal.

- Quantitative Objectives
  Tampa Electric's quantitative objective is to prudently manage its fuel and wholesale energy procurement activities so as to minimize the variance from projected expenditures while taking advantage of cost-saving opportunities that do not result in increased supply risk. Tampa Electric has established a portfolio of fuel and purchased power products with creditworthy counterparties for known volumes and prices.

2012 Risk Management Activities
The company's activities in 2012 that supported the objectives listed above are described in the following section.

- Coal Purchases
  Tampa Electric maintains a portfolio of short-term (also called spot market), medium-term and long-term coal contracts with the goal of minimizing fuel costs and price risk while maintaining reliability of supply. The company procured all of its 2012 coal needs from suppliers with known, established pricing. Thus, the cost for the commodity was known. Tampa Electric continued to monitor deliveries and volume commitments in contracts as the pricing in the coal market changed. Tampa Electric takes advantage of favorable spot market pricing when the coal supply is needed. Coal was used to produce approximately 58 percent of the electricity the company generated in 2012.

- Coal Risk Management Activities
  Tampa Electric's long-established policy of using physical hedges within its portfolio of different term coal supply contracts continued to help protect ratepayers from coal price volatility.

➢ Natural Gas Purchases

In 2012, approximately 41 percent of the electricity Tampa Electric generated was produced using natural gas. Tampa Electric's risk management strategy continues to focus on supply reliability and price volatility reduction. The components critical to the success of the natural gas purchasing strategy are as follows:

- Execution of the natural gas hedge plan approved by the Risk Authorizing Committee;
- Maintaining liquidity by contracting with numerous qualified counterparties;
- Time horizon for natural gas hedging activity that allows the company to hedge natural gas prices into the future;
- Maintaining a minimum and maximum hedge volume percentage by month into the future;
- Maintaining physical natural gas storage capacity near Mobile Bay, Alabama;
- Diversifying interstate pipeline receipt points;
- Expanding access to additional interstate pipelines;
- Maintaining databases and reports to monitor activity;
- Maintaining coordination between power plant operations and natural gas scheduling;
- Maintaining separation of duties and installation of controls consistent with current industry practices.

➢ Natural Gas Hedging Activities

Natural gas prices historically have been more volatile than coal prices. Natural gas prices are more volatile due to the significant variations in natural gas consumption by natural gas fired power plants that increase and decrease generation to follow changes in demand. Additionally, hurricane activity and other weather-related production reductions or demand increases have a significant impact on the natural gas market. Therefore, Tampa Electric continued to use financial instruments to hedge the price of a portion of the natural gas consumed in 2012 to reduce customers' exposure to the volatility of natural gas prices. Tampa Electric used financial floating-price-to-fixed-price swaps to hedge natural gas prices. The costs associated with these instruments are embedded in the price of the instruments and are included in the fuel commodity costs reported by the company. The hedges are described in the following table.

Tampa Electric
Natural Gas Risk Management Activities
January 1, 2012 through December 31, 2012

	Type of Hedge	Mark-to-Market Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-12	Swaps	$(4,265,540)		3,138,497				$3.08
Feb-12	Swaps	$(5,183,010)		2,530,912				$2.68
Mar-12	Swaps	$(4,650,960)		3,187,972				$2.45
Apr-12	Swaps	$(7,270,405)		5,450,966				$2.19
May-12	Swaps	$(7,706,895)		6,810,671				$2.04
Jun-12	Swaps	$(7,164,500)		7,035,403				$2.43
Jul-12	Swaps	$(6,117,660)		6,916,527				$2.77
Aug-12	Swaps	$(5,495,850)		5,806,105				$3.01
Sep-12	Swaps	$(6,371,570)		5,984,744				$2.63
Oct-12	Swaps	$(4,050,300)		4,373,632				$3.02
Nov-12	Swaps	$(1,744,670)		2,714,208				$3.47
Dec-12	Swaps	$(1,496,760)		3,445,415				$3.70
Total		$(61,518,120)		57,395,052				

Consistent with Tampa Electric's non-speculative risk management plan objective, Tampa Electric's natural gas hedging plan provided price stability and certainty during 2012. The losses for 2012 are due to a reduction in the price of natural gas during 2012. The price decline was driven primarily by a supply surplus due to higher supply from non-conventional production of shale gas and reduced demand due to mild weather and continued economic weakness.

Tampa Electric maintains natural gas storage capacity of 1,250,000 MMBtu in order to enhance its physical reliability of gas supply. The storage provides Tampa Electric with improved access to "intraday" natural gas when an operational need arises, provides improved hurricane coverage, and can be used to cost-effectively manage swings in gas supply needs during extreme weather conditions, weekends, holidays and unplanned power plant outages.

Tampa Electric also continues to improve its physical access to natural gas supply by diversifying its receipt points along the Gulf Coast and other areas when opportunities arise.

In summary, financial hedging activities for natural gas resulted in a net loss of approximately $61.5 million in 2012; however, Tampa Electric was successful in reducing price uncertainty and maintaining fuel supply reliability for customers for both its physical and financial hedges.

2012 Market Pricing

Tampa Electric provides a comparison of 2012 fuel prices to the market price for the respective commodity in the following section.

- Coal

  Coal is a commodity with a great range of potential quality characteristics. Market indexes provide a guide to current market pricing but are not specific enough to accurately demonstrate the market price of a particular coal. Market prices for coal are most accurately determined by competitive bid solicitations that specify the required coal quality or characteristics. With the exception of purchases for reliability reasons, short-term purchases for changing plant operation needs and spot market purchases to take advantage of favorable pricing, Tampa Electric purchases coal at prices determined by competitive bid solicitations; therefore, the company's purchases are at market. A comparison of coal contract prices for 2012 to the average acceptable bid price or index price is provided in the following table. Unless otherwise stated, the prices represent the market at the time each contract was entered into and are not representative of today's market. Any comparison to current market prices overlooks the market conditions that existed at the time the coal was procured.

REDACTED

Tampa Electric
Coal Contract to Market Indicator Price Comparisons

Supplier (Mine)	Contract ($ / MMBtu)	Market Indicator ($ / MMBtu)	Difference	Market Indicator Source	Note
Knight Hawk	[redacted]	$3.07	[redacted]	GEN-2009-01 December2007	1
Warrior	[redacted]	$3.00	[redacted]	GEN-2009-01 December2007	1
K H-2012SP1-09	[redacted]	$3.89	[redacted]	Gen 2012-01 (issued 10.12.2011)	1
Allied Res-11LT1-15	[redacted]	$3.87	[redacted]	Gen 2011-01 (issued 2.23.2011)	1
Allied Res-11CP1-15	[redacted]	$3.08	[redacted]	ICAP United, Inc - Coal 6/24/09	2,3
KenAm-11CP1-09	[redacted]	$4.03	[redacted]	ICAP United, Inc - Coal 8/31/2011	2
Armstrong-11LT1-09	[redacted]	$3.87	[redacted]	Gen 2011-01 (issued 2.23.2011)	1
Patriot 2012SP1-09	[redacted]	$3.89	[redacted]	Gen 2012-01 (issued 10.12.2011)	2
Patriot 2012SP2-09	[redacted]	$3.27	[redacted]	ICAP United, Inc - Coal 11/9/2012	2
Glencore 2012SP1-LS	[redacted]	$5.55	[redacted]	Polk-LS-2012-01 (issued July 28,2011)	1, 4
Valero 2012 A 01	[redacted]	$3.45	[redacted]	Polk-PC-2012-01 (issued August 11, 2011)	1

Notes:
The contract $/MMBTU refers to the initial price of the contract at its inception. This price could be subject to escalation per the terms of the contract.
All prices are determined on a fully delivered basis. Index values have also been calculated on a delivered basis for comparison purposes.

1. The bid solicitation price is the average price submitted of all acceptable coal bids.

2. Pricing based on ICAP United Inc. - Daily Coal price index.

3. Call / Put option entered into in June 2009.

4. While the Glencore $/MMBtu was [redacted], the [redacted] yielded the lowest overall cost.

- Natural Gas
  Tampa Electric purchases natural gas at prices that are set by published indexes that reflect the market price. Most of the monthly baseload gas is purchased at a price relative to the New York Mercantile Exchange natural gas futures last day settlement price. Tampa Electric purchases additional baseload gas at monthly index prices published in *Inside FERC, Gas Market Report*. Tampa Electric uses the indexes representing market prices for natural gas on the Gulf Coast that can be transported to Tampa Electric's service area: Henry Hub, Mobile Bay, or Florida Gas Transmission ("FGT") Zone 1, Zone 2 or Zone 3. For daily and short-term natural gas, Tampa Electric typically purchases natural gas based on the FGT index price published in *Gas Daily*. In rare instances, Tampa Electric also purchases small volumes of spot natural gas needed for short durations at fixed prices. Since the price of natural gas Tampa Electric purchases is based upon a published market index, the company's natural gas purchases are at market.

- No. 2 Oil
  Tampa Electric purchases No. 2 oil for combustion turbines at Polk Station and for Big Bend Station startup. The purchase price is based upon the daily index price published in Platt's *Oilgram* for Gulf Coast Waterborne spot purchases of ultra-low sulfur No. 2 oil. Since the price is determined by the published market index, the price paid by Tampa Electric is at market.

- No. 6 Oil
  Tampa Electric no longer purchases No. 6 oil for Phillips Station. Phillips Station was placed on long term standby in September 2009.

- Propane
  Tampa Electric purchases propane for Polk Unit No. 1. The purchase price is based upon the average of daily index prices published by Oil Price Information Service at Mont Belvieu, the primary propane hub for the southern United States. Since the price is determined by the published market index, the price paid by Tampa Electric is at market.

TAMPA ELECTRIC COMPANY
FUEL PROCUREMENT AND WHOLESALE POWER PURCHASES
RISK MANAGEMENT PLAN
2014

Introduction

Tampa Electric serves its retail customers' electricity needs through a portfolio of generation and wholesale purchases. Tampa Electric's generation fuel mix is primarily a blend of coal and natural gas. While fuel mix diversity enhances long-term reliability, the reliance on natural gas can potentially increase variation in fuel prices. The company's risk management activities reduce the impact of price uncertainty and volatility to the Fuel and Purchased Power Cost Recovery Clause.

I. Qualitative and Quantitative Risk Management Objectives

A. Qualitative objectives

Tampa Electric's goals in managing risks associated with fuel or power purchases are focused on minimizing supply risk to ensure reliability of electric service to its customers at a reasonable price. To the extent price risk can be reduced without compromising supply reliability or imposing unnecessary costs on customers, Tampa Electric is committed to executing strategies to accomplish its risk management goals.

B. Quantitative objectives

Tampa Electric's quantitative objective is to prudently manage its fuel and wholesale energy procurement activities to minimize the variance from projected expenditures while taking advantage of cost-saving opportunities that do not result in increased supply risk. Tampa Electric has established a portfolio of fuel and purchased power products with creditworthy counterparties for known volumes and prices.

II. Oversight & Reporting of Fuel Procurement Activities

The company provides fuel and wholesale energy procurement activities with independent and unavoidable oversight.

A. The TECO Energy Board of Directors established an Energy Risk Management Policy ("Risk Policy"). This policy governs all energy commodities transacting activities at each of TECO Energy's operating units. The scope of this policy includes:

- Roles and responsibilities of various persons and functions with respect to risk management
- Authorized transacting activity
- Risk limits
- Valuation and data management
- Credit risk management
- Reporting
- Compliance and enforcement

B. The Risk Policy established the Risk Advisory Committee ("RAC"). The responsibilities of the RAC include the following activities:

- Reviewing the Risk Management Policy periodically and recommending changes and enhancements for approval by the Board of Directors ("Board").
- Reviewing corporate risk limits for recommendation to the Board.
- Establishing the quantitative limits for operating companies within Board approved corporate risk limits. The RAC may, at its discretion, delegate approval of sub-limits to operating company management.
- Approving parameters for counterparty credit limits and the allocation of limits among the operating companies.
- Establishing guidelines for risk management and measurement.
- Overseeing and reviewing the risk management process and infrastructure.
- Reviewing and approving transacting strategies proposed by the operating companies.
- Understanding and approving methodologies used for valuation and risk measurement.
- Reviewing and approving corporate and operating company risk limits.
- Establishing credit underwriting standards, and monitoring credit risk-taking activities and related exposures.
- Reviewing risk reports, including portfolio risk summaries and profitability and performance summaries.
- Enacting, maintaining, and enforcing limit violation and trader misconduct policies.
- Taking appropriate courses of action when the risk position of a transacting group has exceeded or is approaching the established limits.
- Reviewing and approving new risk management products.
- Presenting periodic reports to the Board or its committees.

C. TECO Energy established a corporate risk management function ("middle office"), which is overseen by the Director of Independent Risk Oversight.

D. Tampa Electric established additional oversight or control mechanisms to ensure compliance with policies and procedures. The following practices

provide checks and balances on fuel and purchased power procurement activities.

- Fuel and wholesale energy procurement activities are conducted in accordance with company guidelines, including review by the operating stations and other management.
- All agreements are formalized in a written contract that is reviewed by legal counsel.
- The contracts are reviewed by the Director, Independent Risk Oversight of TECO Energy's Energy Risk Management Department for potential credit risks and incorporation of appropriate credit protection.
- The company maintains approval authority restrictions based on term and value of the transaction.
- Payments of invoices under each contract are settled and approved by an independent department.
- Each transaction is eligible for review by outside, internal and regulatory auditors.
- Information systems provide transaction authority control, credit monitoring, mark-to-market and value-at-risk analysis and other key controls.

E. In accordance with the Risk Policy, Tampa Electric established commodity specific transaction limits for commodity transactions.

- The Risk Authorizing Committee reviews and approves commodity transaction limits on an individual basis.
- The limits include commodity, physical or financial, tenor (time limit), and dollar amount.
- Only a few individuals are authorized to execute financial hedging transactions.

F. Tampa Electric's Fuels Management Department has updated and formalized its policies and procedures. The key elements of its policies and procedures are:

- Financial hedging of fuel commodities are for mitigation of risk to fuel price uncertainty and volatility.
- Hedging will be conducted in a manner consistent with the Risk Management Plan approved by the RAC.
- Execution of hedges under the Risk Management Plan will be consistent with approved transaction limits for authorized transactors.
- Duties will be separated to assure sufficient control over hedging transactions.
- Hedging activity will be monitored regularly and reported at least once a month to insure consistency with the Risk Management Plan.

G. Reports are generated that summarize the fuel procurement activities of the company. These include monthly financial reports produced by Regulatory Accounting, FERC Electric Quarterly Reports, FERC Form 1,

FERC Form 580, FERC Form 923, FERC Form 552, FPSC Form 423, FPSC A schedules and FPSC E schedules. In addition, position and mark-to-market reports are produced and reviewed by the Director of Independent Risk Oversight. The appropriate entries and related disclosures are made in the company's books and records as required by accounting standards.

III. Risk Assessment

In its Risk Policy, TECO Energy has identified the following types of risks for its commodity portfolio.

A. Market Risk

Market risk is the potential change in value of a commodity contract caused by adverse changes in market factors (price and volatility). The following are types of market risk.

1. **Price Risk:** Price risk refers to the uncertainty associated with changes in the price of an underlying asset. For instance, if a company has a short position in the market (e.g., needs to meet load requirements by purchasing electricity or natural gas), it will be susceptible to price increases. Conversely, if a company is in a long position (e.g., excess generation or natural gas supply), it is exposed to decreases in market prices. Tampa Electric manages its price risk using physical and financial hedges.

   In 2014, Tampa Electric is subject to limited price risk related to variation in coal prices. That price risk is mitigated in part because the company has already contracted for much of its expected coal needs at known prices. Expected market conditions do not currently require further price risk mitigation, for the reasons described in Section IV of this plan.

   Tampa Electric evaluated its exposure to changes in the price for natural gas during 2014 based on the forward price and estimated uncertainty in the price of natural gas and the company's expected usage under both low and high price natural gas cases. Natural gas expenditures decrease in the low case by an estimated $40.0 million and total fuel and purchased power costs decrease by $68.5 million due to lower prices. In the high case, natural gas expenditures increase by an estimated $75.2 million, and the total fuel and purchased power costs increase by $52.6 million. This exposure estimate does not take into account any hedges the company may implement to limit its exposure. Tampa Electric's

hedging strategy with respect to natural gas and purchased power is outlined in Section IV of this plan.

Tampa Electric requires small quantities of fuel oil and maintains a contract that eliminates its supply risk. Due to the small quantities of fuel oil needed for generation, the cost impact caused by price risk is minimal and is therefore not quantified.

2. **Time Spread Risk:** This is the risk that the relationship between two points (i.e., one month versus six months) on the forward curve changes. Because the shape of the fuel or electricity forward curve changes to reflect the market's expectations of spot and future fuel or electricity prices, the relationship between any two points on the curve is not always constant. Because of the nature of its business Tampa Electric has little reason or opportunity to offset energy commodity requirements in one month with resources delivered in another month. Therefore, time spread risk is not a significant issue for Tampa Electric.

3. **Liquidity Risk:** Liquidity risk is associated with the lack of marketability of a commodity. It includes the risk of an adverse cost or return variation stemming from the lack of marketability of a financial instrument. Liquidity risk may arise because a given position is very large relative to typical trading volumes of like commodity and contract tenor, or because market conditions are unsettled. Liquidity risk is usually reflected in a wide bid-ask spread and large price movements in response to any attempt to buy or sell. A firm facing the need to quickly unwind a portfolio of illiquid instruments may find it necessary to sell at prices far below fair value. Tampa Electric is not exposed to liquidity risk for natural gas financial instruments since the company does not purchase instruments for resale. Tampa Electric does have some liquidity risk for wholesale power transactions since the Florida market has a limited number of participants.

4. **Basis Risk:** Basis risk is the risk exposure due to a difference in commodity value between different delivery points. Electricity markets are regional. Prices can be different at different locations because of differences in both supply costs and the cost of transmission between the two locations. These price differences are dynamic, primarily due to changes in transmission availability between the two locations. Due to the stability of the coal market, Tampa Electric's negligible use of oil, and the indexing of its natural gas contract pricing, basis risk is not a significant issue for the company.

Fundamentally, market risk is created by the existence of "open"

positions. An open position is the difference between an existing requirement and the ability to meet that requirement with existing resources.

B. Volume Risk

Volume risk is the potential adverse economic impact of unanticipated changes in supply or demand. Tampa Electric faces supply risk, because there is uncertainty associated with the availability of generating units or fuel availability for those units. If a generating unit fails, Tampa Electric must replace the power with another unit's generation or with purchased power at market prices. Tampa Electric also faces demand risk since there is uncertainty associated with customer demand, and thus uncertainty in the determination of the fuel or energy purchase volumes necessary to supply such demand. Tampa Electric's volume risk for fuel and purchased power in 2014 will be managed operationally and through contract terms enforcement, including appropriate legal remedies, should a party default.

C. Credit Risk

Credit risk is the risk of financial loss due to a counterparty's failure to fulfill the terms of a contract on a timely basis. It includes both settlement risk associated with payment for fuel or energy received, as well as the potential risk that the counterparty defaults on an obligation to provide or receive fuel or energy. Credit risk depends on the probability of counterparty default, the concentration of credit exposure with a small number of counterparties, the total amount of exposure, and the volatility of markets. Tampa Electric's credit risk will vary based on the number of its trading counterparties and the mark-to-market value of its hedge transactions. Tampa Electric's existing credit risk is minimal since it uses a wide variety of counterparties, and has systems and processes in place to monitor and control credit risk.

D. Administrative Risk

Administrative risk is risk of loss associated with deficiencies in a company's internal control structure and management reporting due to human error, fraud or a system's inability to adequately capture, store and report transactions. The company has consistently maintained appropriate administrative controls for entering and administration of commodity transactions.

IV. Risk Management Strategy and Current Hedging Activity

Tampa Electric's risk management strategy is designed to limit exposure to different types of risk that are applicable to the company's operation.

A. Market Risk

Tampa Electric's potential market risk is the result of open positions in four commodities:

- Coal
- Natural Gas
- Fuel Oil
- Purchased Power

System energy requirements during 2014 are projected to be served in the proportions shown in the following table.

Commodity	Percent of System Energy
Coal	59
Natural Gas	37
No. 2 Oil	0
No. 6 Oil	0
Purchased Power	4

Based on Tampa Electric's assessment of market risk factors, the company has implemented the market risk management strategies described below.

1. **Coal:** Tampa Electric has contracted for much of its expected coal needs for 2014 through bilateral agreements with coal producers. The company will provide the projected amounts in both tons and dollars in its 2014 projection filing to be submitted August 30, 2013. Coal market pricing has retreated from record high levels in 2008. In 2013, coal prices have been relatively stable, and prices are expected to remain stable in 2014. Tampa Electric has secured a portion of its coal needs for 2014, reducing exposure to price volatility and mitigating coal volume risk. Tampa Electric's contracts with suppliers also incorporate legal remedies in the event of default, which address volume risk.

2. **Fuel Oil:** In 2014, Tampa Electric will continue to purchase its fuel oil needs at indexed market prices. Oil represents less than one percent of the company's needs on a GWH basis, and therefore, associated price impact from risk is minimal. Tampa Electric maintains a contract with a local supplier to deliver all of its needs, which mitigates supply risk.

3. **Natural Gas:** Tampa Electric continues to implement prudent financial hedging strategies for natural gas requirements. In 2013, the company used swap agreements—the exchange of a payment tied to the value of a natural gas index for a fixed payment—to hedge natural gas. In keeping with the company's approved risk management plan, Tampa Electric plans to hedge a significant percentage of its projected natural gas usage in 2014.

Tampa Electric uses the forward pricing information of the New York Mercantile Exchange ("NYMEX") natural gas forward price curve in developing natural gas price hedging strategy. Tampa Electric also subscribes to industry publications that provide information about underlying issues affecting the availability and price of natural gas and other commodities. The purpose of Tampa Electric's natural gas hedge plan is to reduce natural gas price volatility by utilizing financial instruments relying on three key variables: price, volume and time.

Tampa Electric projects prices during the company's annual fuel budgeting process. The volume of natural gas that the company will hedge falls between a minimum and a maximum percentage of the expected natural gas burn. The percentages vary according to the time remaining until the contract month.

Tampa Electric's approved Risk Management Plan describes the following key elements of the company's natural gas hedging strategy: (1) natural gas prices can be hedged up to 24 months into the future; (2) nearer months can be hedged for a greater percentage of the expected volume than outer months; and (3) natural gas options can be used for financial hedging.

Currently, Tampa Electric estimates about [redacted] percent of its total 2013 natural gas purchases will be covered by financial hedges. The net effect of these hedges is estimated to be a [redacted] of approximately [redacted] For 2014, Tampa Electric has approximately [redacted] percent hedged with a currently estimated [redacted] of [redacted].

4. **Purchased Power:** Total forecasted purchased power for 2014 is 713 GWH. As of July 2013, Tampa Electric has physically hedged 328 GWH's of its 2014 expected purchased power needs through pre-scheduled purchased power agreements. The remaining GWH's of 2014 forecasted wholesale energy purchases will be purchased from as-available cogenerators or on the short-term, non-firm market for economy purposes, which are not hedged.

The company's purchased power contracts include a fuel component; therefore, Tampa Electric has exposure to fuel price risk for its wholesale energy purchases, particularly for purchased power supplied from natural gas-fired generation. Tampa Electric does not currently hedge wholesale energy transactions with financial instruments due to the lack of a liquid, published wholesale energy market and appropriate available instruments.

Tampa Electric is responsible for natural gas fuel delivery on two purchase contracts for peaking power. Although this contract volume is not currently included in the company's hedging portfolio, Tampa Electric continually assesses whether it should be added.

In summary, Tampa Electric's planned operations in 2014 result in nominal market risk associated with coal and fuel oil. Non-price risks associated with natural gas and purchased power are also minimal. Therefore, while the company continues to evaluate risk for all fuel and energy commodity transactions, it is currently focused on mitigating the price risk associated with natural gas and purchased power.

5. **Volume Risk:** Hedging of volumetric risk is problematic due to a limited number of viable financial hedging instruments. Tampa Electric has identified the following hedges.
   - Maintaining appropriate inventory stockpiles provides a physical hedge against volume risk.
   - "Swing" contracts enable the buyer to take variable volumes up to a predefined limit.
   - Full requirement contracts enable the buyer to take any volume up to total usage.

   Tampa Electric uses inventory swing contracts and full requirements contracts where needed commodity volumes are small and in situations where commodity volumes are unpredictable in volume and/or timing. Other alternatives will continue to be identified, assessed and implemented as necessary.

6. **Credit Risk:** TECO Energy's credit risk management process is composed of the following primary steps.
   - Gather counterparty information for initial evaluation.
   - Assess counterparty creditworthiness and assign credit limit.
   - Determine credit collateral requirements, as needed.
   - Request, review and monitor contractual requirements, legal covenants, collateral documents and credit provisions.
   - Quantify counterparty exposure and measure against approved limits.
   - Monitor counterparty and credit support provider qualities.

- Prepare credit exposure reports on a daily basis that are reviewed prior to entering into transactions.

7. **Administrative Risk:** Tampa Electric maintains energy trading risk management systems and processes to efficiently track, monitor and evaluate hedging activities. Tampa Electric's administrative processes and system controls have passed repeated internal and external (Sarbanes-Oxley) audits.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
HEDGING ACTIVITY REPORT
EXHIBIT NO. ___ (JBC-3), PAGE 1 OF 1
FILED: AUGUST 16, 2013

Tampa Electric
Natural Gas Risk Management Activities
January 1, 2013 through July 31, 2013

		Type of Hedge	Mark-to-Market Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-13		Swaps	($1,482,130)	[redacted]	4,355,657	[redacted]	[redacted]	[redacted]	$3.35
Feb-13		Swaps	($1,744,150)	[redacted]	5,362,808	[redacted]	[redacted]	[redacted]	$3.23
Mar-13		Swaps	($828,170)	[redacted]	3,761,758	[redacted]	[redacted]	[redacted]	$3.43
Apr-13		Swaps	$1,127,945	[redacted]	4,873,898	[redacted]	[redacted]	[redacted]	$3.98
May-13		Swaps	$1,794,365	[redacted]	5,474,303	[redacted]	[redacted]	[redacted]	$4.15
Jun-13		Swaps	$1,902,130	[redacted]	6,500,554	[redacted]	[redacted]	[redacted]	$4.15
Jul-13		Swaps	($190,245)	[redacted]	5,973,210	[redacted]	[redacted]	[redacted]	$3.71
Total			$579,745	[redacted]	36,302,188	[redacted]			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 53
PARTY Tampa Electric Company (TECO) (Direct)
DESCRIPTION Brent Caldwell - JBC-3

54

FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-12)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 54
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0001-0109]

Q.

In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 through 2:

Please quantify and discuss all the costs and benefits under the following three scenarios. If the billing system does not have the ability to implement a particular scenario, explain why.

(a) The January first billing cycle is set for January 1 or later each year (i.e., first billing cycle for January would not begin in December of prior year);

(b) The effective date of new factors would be with the first billing cycle in February each year;

(c) The effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (i.e., any December or November usage would be billed under prior factors).

A.

(a) This scenario reflects FPL's current practice; therefore, no additional costs are associated with making the annual fuel cost recovery clause effective date of the new factors to begin on January 1 or later each year. Factor update processes are standardized when using this methodology. No changes to the billing system are required.

(b) This scenario is similar to FPL's current practice; therefore, no additional costs are associated with making the annual fuel cost recovery clause effective date of the new factors to begin with the first billing cycle in February each year. Factor update processes are standardized when using this methodology. No changes to the billing system are required.

(c) FPL's billing system is programmed to calculate customer's bills using the billing factors that are in effect on the account's scheduled meter reading date. All usage for the billing period is calculated using the billing factors in effect regardless of when the power was actually consumed. In order for the effective date of the new factors to begin with the first billing cycle in January, but to apply prior factors to power consumed in December or November and apply the new factors to power consumed in January, would require significant changes to FPL's billing system. This scenario would require: 1. The addition of new proration logic that will allow for multiple consumption and meter reading rows within one billing period; 2. Changes to the billing calculation programs to be able to process multiple consumption periods for all rates and apply different billing factors within one billing period; and, 3. Changes to the customer bill statement to display the number of service days, consumption, meter readings, and billing factors associated with each consumption period. This represents a significant change in the data model relationship within FPL's billing system. The cost to make the required changes to the billing system is estimated at $1.9MM and would require approximately 12-14 months to complete. Additional operational costs would also be incurred during the month the factors become effective, such as increased postage costs due to a higher number of two-page bills, and a higher number of customer inquiries to explain that month's billing.

Q.

In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 through 2:

Please discuss when and how customers receive notice of the new January factors.

A.

When there is change in customer rates or other charges, such as fuel, Florida Power & Light Company notifies its customers of the change in the following manner:

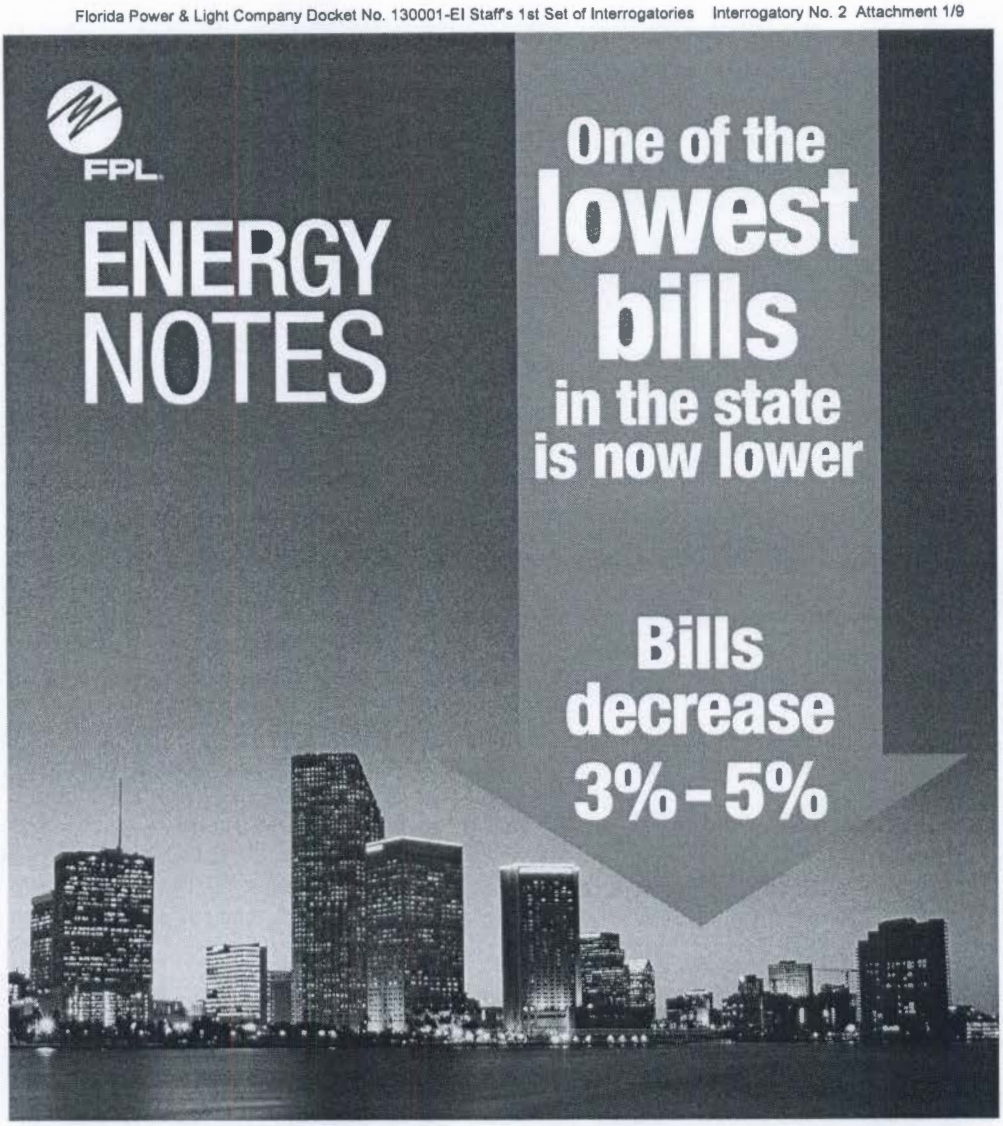
30-day pre-notification: 30 days prior to the rate change, fuel charge change or other adjustment appearing on a customer's bill, FPL places a message on the bill statement informing customers of the upcoming change.

Online rates schedules: 30 days prior to a rate change, fuel charge change or other adjustment, FPL updates its online residential and business rates schedules. In the 30 days leading up to a change, customers can see both their current schedule and the next upcoming schedule. Once the change has become effective, only the new schedule remains visible. (Posted to www.FPL.com/rates)

Annual rates bill insert: Per Florida Administrative Code 25-6.093, at least once per year, FPL gives customers a summary of major rate schedules, including the fuel charge. This annual summary is transmitted via bill insert to residential and business customers in a month that the new charges take effect, typically January. This notice follows the 30-day pre-notification addressed above. (see attachments named "Energy News" and "Energy Notes")

Bill insert notice: In addition to the annual rates bill insert, FPL provide notice of all other rates or charge changes that occur throughout the year. This notice is transmitted via bill insert to residential and business customers in the month that the adjustment takes effect and typically appears as a "story" in their bill insert newsletter. This notice follows the 30-day pre-notification addressed above.

"New connects" bill insert: Per F.A.C. 25-6.093, not later than 60 days after the commencement of service, FPL provides new customers with a summary of major rate schedules via a bill insert. (see attachment named "Residential and Business Customer Rate Summary")



While most of our business customers already have the lowest bill in the state, you'll now pay even less in 2012. Starting this month, our typical business customer's monthly bill will decrease by about 3 to 5 percent, depending on usage and other factors, due to lower projected fuel costs. FPL asked for this reduction in your bill and received approval from the Public Service Commission in December.

"For 2012, oil prices are still high, but our investments in recent years to modernize our power plant fleet – phasing out older, oil-fired units with cleaner, more efficient natural gas-fired generating capacity – are helping protect our customers from higher fuel charges," said FPL President and CEO Armando J. Olivera.

Helping to keep your bills low are facilities such as the West County Energy Center, which came online fully in June 2011. The state-of-the-art, natural gas-fueled center saved customers more than $20 million in its first six months of operation.

Visit **www.FPL.com/value** to learn more about how we offer our business customers a bill that's significantly lower than the national average and one of the lowest of Florida's 55 electric utilities.

What you need to know

This edition of *Energy Notes* includes the latest information about your monthly bill, rates and programs we offer to help you manage your electric usage.

How your rate is determined

A business rate classification is based on your maximum monthly electrical usage and when you use electricity. Qualifying for another rate may produce savings for some customers.

If your business can shift a significant part of electric usage to off-peak times when the demand for electricity is lower, you may benefit from our time-of-use rates. With TOU rates, you are billed at a lower rate for off-peak usage and a higher rate for peak period usage. To benefit, your electrical use must be shifted away from the following peak hours, Monday through Friday:

- April 1 to Oct. 31, noon to 9 p.m.*
- Nov. 1 to March 31, 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m.*

**Excludes select holidays including Thanksgiving, Christmas and New Year's Day*

Visit **www.FPL.com/yourbill** for more information about your bill or to view available business rate options that might be more economical for your business.

Service charges

The Florida Public Service Commission allows utilities to charge customers for certain services to recover the related costs.

Current service charges are:

- $14.88 to open an account
- $17.66 to reconnect service after disconnection either for non-payment or violation of a rule or regulation
- $23.24 or 5 percent of the payment amount, whichever is greater, for each payment returned by a bank
- 1.5 percent added to overdue bills, applied on the past-due balance each month
- $5.11 when a field visit is made to collect on an overdue account and payment is made to the FPL representative.

Gross receipts tax

FPL pays 2.5 percent of gross electric revenues to the state in the form of a gross receipts tax. This tax appears as a separate line item on your bill.

Resale of electric service prohibited

The Florida Administrative Code prohibits the resale of electricity for a profit. The actual cost of electricity billed by FPL may be reasonably allocated among tenants, lessees and other entities as long as no profit is made.

Business Customer Rate Summary

Effective January 2012

	kW Demand	Monthly Customer Charge	Demand Charge per kW	Total Demand Charge per kW	On-Peak Demand Charge	Total Demand Charges On-Peak	Demand Charges Firm	Total Demand Charges Firm	Maximum Demand Charge	Energy Charges	< 1,000 kWh/ On-Peak Energy Charge	> 1,000 kWh/ Off-Peak Energy Charge	Storm Charge	Fuel Charge per kWh	< 1,000 kWh/ Winter* On-Peak Fuel Charge	> 1,000 kWh/ Winter* Off-Peak Fuel Charge	Summer** On-Peak Fuel Charge	Summer** Off-Peak Fuel Charge
BUSINESS																		
General Service Non-Demand (GS-1)	0-20	$6.89								5.662¢			0.097¢	3.688¢				
General Service Non-Demand-TOU (GST-1)		$13.53									9.688¢	3.860¢	0.097¢		4.529¢	3.378¢	5.830¢	2.603¢
General Service Demand (GSD-1)	21-499	$16.44	$6.50	$10.04						1.551¢			0.068¢	3.687¢				
C/I Load Control, General Service [CILC-1(G)]+		$122.00	$3.20	$3.20	$1.32	$5.60	$6.92	$11.20			1.279¢	1.279¢	0.065¢		4.528¢	3.378¢	5.829¢	2.603¢
General Service Demand-TOU (GSDT-1)		$22.77			$6.50	$10.04					3.271¢	0.804¢	0.068¢		4.528¢	3.378¢	5.829¢	2.603¢
High Load Factor-TOU (21 - 499 kW)		$22.77			$7.83	$11.37			$1.81		1.348¢	0.804¢	0.068¢		4.528¢	3.378¢	5.829¢	2.603¢
General Service Large Demand (GSLD-1)	500-1,999	$50.13	$7.60	$11.69						1.073¢			0.065¢	3.683¢				
General Service Large Demand-TOU (GSLDT-1)		$50.13			$7.60	$11.69					2.198¢	0.577¢	0.065¢		4.523¢	3.374¢	5.822¢	2.600¢
Curtailable Service (CS-1)		$50.13	$7.60	$11.69						1.073¢			0.076¢	3.683¢				
Curtailable Service-TOU (CST-1)		$50.13			$7.60	$11.69					2.198¢	0.577¢	0.076¢		4.523¢	3.374¢	5.822¢	2.600¢
High Load Factor-TOU (500 - 1,999 kW)		$50.13			$7.83	$11.89			$1.81		0.697¢	0.697¢	0.065¢		4.523¢	3.374¢	5.822¢	2.600¢
General Service Large Demand (GSLD-2)	2,000+	$179.19	$7.60	$11.66						0.990¢			0.043¢	3.641¢				
General Service Large Demand-TOU (GSLDT-2)		$179.19			$7.60	$11.66					1.641¢	0.749¢	0.043¢		4.478¢	3.340¢	5.764¢	2.574¢
Curtailable Service (CS-2)		$179.19	$7.60	$11.66						0.990¢			0.086¢	3.641¢				
Curtailable Service-TOU (CST-2)		$179.19			$7.60	$11.66					1.641¢	0.749¢	0.086¢		4.478¢	3.340¢	5.764¢	2.574¢
High Load Factor-TOU (2,000 kW or more)		$179.19			$7.83	$11.89			$1.81		0.642¢	0.642¢	0.043¢		4.478¢	3.340¢	5.764¢	2.574¢
General Service Large Demand (GSLD-3)	2,000+ >69KV	$1,441.88	$6.32	$11.25						0.765¢			0.006¢	3.526¢				
General Service Large Demand-TOU (GSLDT-3)		$1,441.88			$6.32	$11.25					0.864¢	0.729¢	0.006¢		4.330¢	3.229¢	5.573¢	2.489¢
Curtailable Service (CS-3)		$1,441.88	$6.32	$11.25						0.765¢			0.006¢	3.526¢				
Curtailable Service-TOU (CST-3)		$1,441.88			$6.32	$11.25					0.864¢	0.729¢	0.006¢		4.330¢	3.229¢	5.573¢	2.489¢
C/I Load Control Program, Transmission [CILC-1(T)]	2,000+ >69KV	$1,866.00			$1.29	$5.53	$6.79	$11.03			0.712¢	0.712¢	0.006¢		4.330¢	3.229¢	5.573¢	2.489¢
C/I Load Control Program, Distribution [CILC-1(D)]	500+	$175.00	$3.17	$3.17	$1.35	$5.63	$7.12	$11.40			0.764¢	0.764¢	0.042¢		4.472¢	3.336¢	5.757¢	2.571¢

* Nov. 1 – March 31 ** April 1 – Oct. 31

130001-Hearing Exhibit - 00005

Florida Power & Light Company Docket No. 130001-EI Staff's 1st Set of Interrogatories Interrogatory No. 2 Attachment 2/9

About your deposit

Our practices regarding deposits ensure that all customers are treated fairly. We may ask customers opening new accounts to pay a deposit for electric service.

Businesses have the choice of paying required deposits with cash or check. Acceptable alternatives to a deposit include an irrevocable bank letter of credit or surety bond. However, these alternatives are recommended for deposits of more than $1,000 because for less than that amount they are not cost effective. Deposits are based upon twice the average monthly billing, with a $25 minimum.

For deposits held more than six months, you will earn 6 percent interest from the time the deposit is paid in full, and 7 percent interest for a deposit held 23 continuous months or more, provided a prompt payment record has been maintained for the past 12 months. After four months and again after 12 months of service, we may ask you to increase the deposit if the actual average bill amount is higher than projected.

Visit **www.FPL.com/rates** for more information.

Genius Jones, a children's clothing and furniture store in Miami, received cost-saving recommendations through a free Business Energy Evaluation from FPL.

Lower your bills, increase profits

In addition to providing most business customers with the lowest electric bill in the state, we offer rebates and energy efficiency programs to further your business savings. In 2011, we issued $11 million in program rebates and provided more than 11,000 Business Energy Evaluations. Interested in getting a free, customized plan that includes ways to cut your energy usage and save up to 30 percent on your electric bills? Just visit **www.FPL.com/bee.**

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Find the latest tips, news and updates online at:
www.facebook.com/FPLconnect
www.twitter.com/insideFPL
www.FPLblog.com
www.youtube.com/FPL

It's a New Year's resolution that's easy to keep! Save time and stamps using FPL Automatic Bill Pay® or FPL Pay Online in 2012. Just visit **www.FPL.com/bizpayoptions** to get started with one of these simple and free ways to pay your business bill.

Learn more: Scan with smart device

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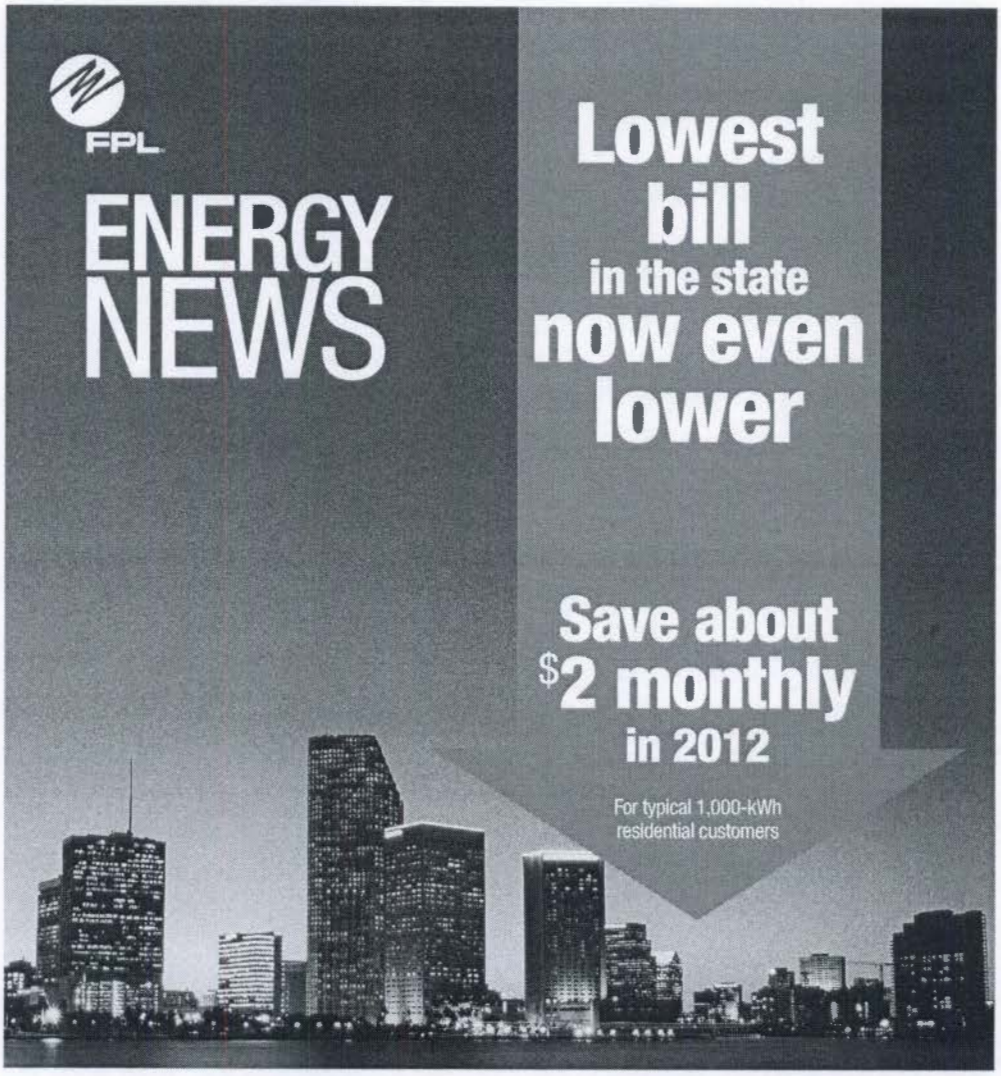
Florida Power & Light Company
P.O. Box 14000, Juno Beach, FL 33408

130001 Hearing Exhibit - 00006



Starting this month, customers will pay even less for electricity due to lower projected fuel costs. This reduction in the fuel charge, along with other adjustments, will result in a typical 1,000-kWh residential customer paying about $2 less per month, from $96.54 in December 2011 to $94.62 beginning in January 2012. FPL asked for this reduction in your bill and received approval from the Public Service Commission in December.

"For 2012, oil prices are still high, but our investments in recent years to modernize our power plant fleet – phasing out older, oil-fired units with cleaner, more efficient natural gas-fired generating capacity – are helping protect our customers from higher fuel charges," said FPL President and CEO Armando J. Olivera.

Helping to keep your bills low are facilities such as the West County Energy Center, which came online fully in June 2011. The state-of-the-art, natural gas-fueled center saved customers more than $20 million in its first six months of operation.

Visit **www.FPL.com/value** to learn more about how we deliver a customer bill that's significantly lower than the national average and the lowest of Florida's 55 electric utilities.

What you need to know

This edition of *Energy News* includes the latest information about your monthly bill, rates and programs we offer to help you manage your electric usage.

How your rate is determined

Most residential customers have standard residential service. This includes a price incentive to conserve energy. Electricity usage at or below 1,000 kWh per month is billed at a lower rate.

Standard service costs (excluding utility taxes and franchise fees) include:

- Monthly non-fuel price of 5.184 cents per kWh for the first 1,000 kWh used
- Monthly non-fuel price of 6.184 cents per kWh for usage over 1,000 kWh
- Fuel price of 3.343 cents per kWh for the first 1,000 kWh used
- Fuel price of 4.343 cents per kWh for usage over 1,000 kWh
- Storm charge of 0.108 cents per kWh used
- Gross receipts tax of 2.5 percent, collected on behalf of the state of Florida
- Customer charge of $5.90 per month.

Service charges

The Florida Public Service Commission allows utilities to charge customers for certain services to recover the related costs. Current service charges are:

- $14.88 to open an account
- $17.66 to reconnect service after disconnection either for non-payment or violation of a rule or regulation
- $23.24 or 5 percent of the payment amount, whichever is greater, for each payment returned by a bank
- 1.5 percent added to overdue bills, applied on the past-due balance each month
- $5.11 when a field visit is made to collect on an overdue account and payment is made to the FPL representative.

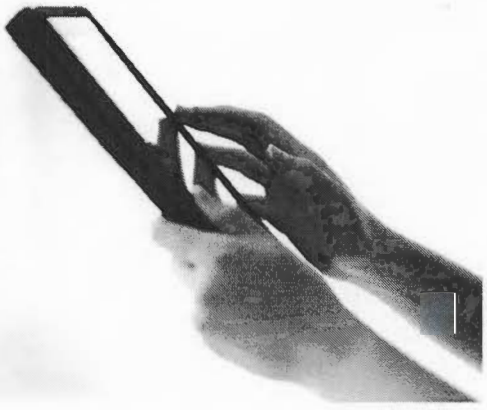
Deposits

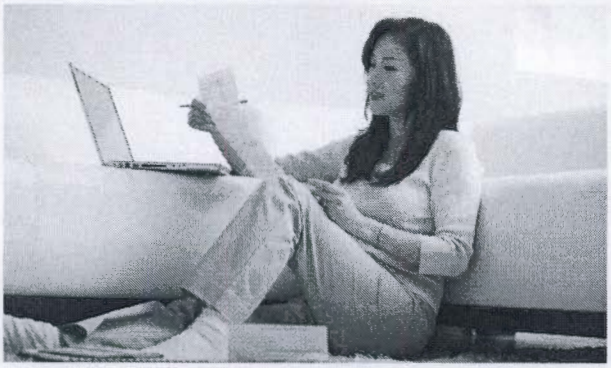
Our practices regarding deposits ensure that all customers are treated fairly. We may ask customers opening new accounts to pay a deposit for electric service that is based upon the expected cost of two months' electricity at the premises when occupied, with a $25 minimum. This deposit may be waived by FPL for those with an excellent credit score.

Resolve to simplify your life in 2012

It's a New Year's resolution that's easy to keep! Save time and stamps using FPL Automatic Bill Pay® or FPL Pay Online in 2012. Just visit **www.FPL.com/yourpayoptions** to get started with one of these simple and free ways to pay your bill.

Learn more: Scan with smart device





If your usage increases and the deposit on hand is less than your two months' average billing, we may ask you to pay the difference in order to bring the deposit to the required level. Additionally, if your account remains open for more than six months, your deposit will earn 6 percent interest from the time the deposit is paid in full. The interest is credited to your account annually. The deposit is returned with any earned interest when the account is closed or after 23 consecutive months of service if:

- You have not paid after the past-due date of your regular bill more than once within the past 12 months, and you have not paid with a check that has been refused by a bank
- Your service has not been disconnected for non-payment within the past 12 months
- You have not used electric service in a fraudulent or unauthorized manner.

Visit **www.FPL.com/yourbill** for more information about your bill, rates and charges.

Free tax help available

You may qualify for free income tax assistance. Low- to moderate-income Floridians may be eligible to receive free tax help through the IRS Volunteer Income Tax Assistance or Tax Counseling for the Elderly programs. Also, ask your tax advisor about the Earned Income Tax Credit, a refundable credit for lower-income working families and individuals. Generally, income and family size determine a taxpayer's eligibility and the credit amount. Contact the IRS at 1-800-829-1040 or visit **www.irs.gov** for information.

Connect with us

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www.facebook.com/FPLconnect **www.FPLblog.com**
www.twitter.com/insideFPL **www.youtube.com/FPL**

Ask the Energy Expert

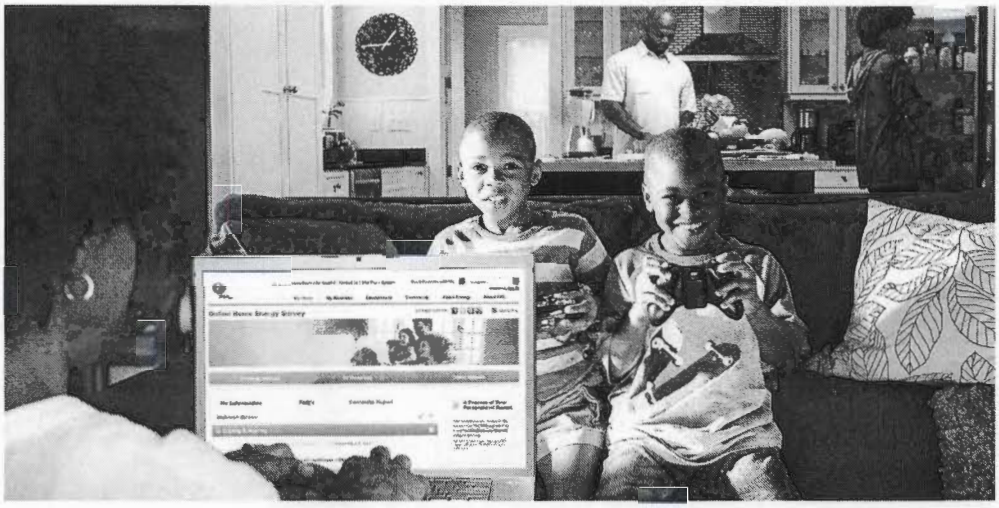
*To submit a question on any energy-related topic or to comment on this one, please visit **www.FPL.com/asktheexpert**.*

Q We are seasonal residents. Can you give us information regarding the loss of efficiency as an A/C unit ages?

– Sherrie M., Sarasota

A The performance and efficiency of an air conditioner does decline a little with age. Additionally, newer central A/C units have a better seasonal energy efficiency ratio, or SEER, than older models. Those made since September 2006 have a SEER of at least 13 compared to 10. Replacing a typical 3-ton SEER 10 with a 13 would save the average FPL customer $120 annually, with additional savings possible for each SEER upgrade above 13.

As one of our 400,000 seasonal customers, it's likely you only live in Florida and use your A/C about one-third of the time. Therefore, it may take you longer to accumulate the savings after replacing your central A/C system. To learn about FPL's air conditioning rebate or to try our A/C cost calculator, visit www.FPL.com/acsavings.



Saving money is now easier than ever

As an FPL customer, you have the lowest electric bill in the state, and it's easier than ever to make it even lower by getting a personalized energy-savings plan in the New Year. Our Online Home Energy Survey helps you identify energy-saving opportunities around your home, and it now has new features including:

- A sleek, new design making the survey more user-friendly
- A welcome screen showing the steps needed to get a personalized plan
- A progress bar helping track your steps to completion
- Streamlined navigation making it easier to finish, view and print your plan.

With an Online Home Energy Survey, you'll receive an analysis of your home's energy usage and get recommendations for energy efficiency programs that can provide further savings.

Complete your survey today and start the New Year with a personalized energy-savings plan for your home at **www.FPL.com/newohes**.

Find savings in your home

Did you know?

It can power your lunch hour but not your whole day like FPL can. For about the price of a slice of pizza, we give you the energy you need to power your life.*

Learn more: Scan QR code or visit www.FPL.com/value

*Based on typical 1,000-kWh residential customer bill

FPL Energy News is published by
Florida Power & Light Company
P.O. Box 14000, Juno Beach, FL 33408

Residential and Business Customer Rate Summary

Rates effective as of January 2012.
Visit **www.FPL.com/rates** for a complete list of all rates or for an electronic version of this insert.

RESIDENTIAL	kW Demand	Monthly Customer Charge	Demand Charge per kW	Total Demand Charge[1] per kW	Demand Charge per On-Peak kW	Total Demand Charge[1] per On-Peak kW	Demand Charge per Firm kW	Total Demand Charge[1] per Firm kW	Maximum Demand Charge per Firm kW	Energy Charge[2] per kWh	< 1,000 kWh[3]/ On-Peak Energy Charge[2]	> 1,000 kWh[3]/ Off-Peak Energy Charge[2]	Storm Surcharge	Fuel Charge per kWh	< 1,000 kWh/ Winter[4] On-Peak Fuel Charge	> 1,000 kWh/ Winter[4] Off-Peak Fuel Charge	Summer[4] On-Peak Fuel Charge	Summer[4] Off-Peak Fuel Charge
Residential Service (RS-1)		$5.90									5.184¢	6.184	0.108¢		3.343¢	4.343¢		
Residential TOU Service (RST-1)		$16.04									9.207¢	3.927	0.108¢		4.529¢	3.378¢	5.830¢	2.603¢
Residential Service Dynamic Price Response (RSDPR-1)																		
- Non-conservation Pricing Hours		$4.75								5.293¢			0.108¢		3.343¢	4.343¢		
- Conservation Pricing Hours		$4.75								27.315¢			0.108¢		3.343¢	4.343¢		
BUSINESS																		
General Service Non-Demand (GS-1)	0-20	$6.89								5.662¢			0.097¢	3.686¢				
General Service Non-Demand-TOU (GST-1)		$13.53									9.688¢	3.860	0.097¢		4.529¢	3.378¢	5.830¢	2.603¢
General Service Demand (GSD-1)	21-499	$16.44	$6.50	$10.04						1.551¢			0.068¢	3.667¢				
C/I Load Control, General Service [CILC-1(G)]**		$122.00	$3.20*	$3.20*	$1.32**	$5.60***	$6.92	$11.20			1.279¢	1.279	0.065¢		4.528¢	3.378¢	5.829¢	2.603¢
General Service Demand-TOU (GSDT-1)		$22.77			$6.50	$10.04					3.271¢	0.804	0.068¢		4.528¢	3.378¢	5.829¢	2.603¢
High Load Factor-TOU (21 - 499 kW)		$22.77			$7.83	$11.37			$1.81		1.348¢	0.804	0.068¢		4.528¢	3.378¢	5.829¢	2.603¢
General Service Large Demand (GSLD-1)	500-1,999	$50.13	$7.60	$11.69						1.073¢			0.065¢	3.683¢				
General Service Large Demand-TOU (GSLDT-1)		$50.13			$7.60	$11.69					2.198¢	0.577	0.065¢		4.523¢	3.374¢	5.822¢	2.600¢
Curtailable Service (CS-1)		$50.13	$7.60	$11.69						1.073¢			0.076¢	3.683¢				
Curtailable Service-TOU (CST-1)		$50.13			$7.60	$11.69					2.198¢	0.577	0.076¢		4.523¢	3.374¢	5.822¢	2.600¢
High Load Factor-TOU (500 - 1,999 kW)		$50.13			$7.83	$11.89			$1.81		0.697¢	0.697	0.065¢		4.523¢	3.374¢	5.822¢	2.600¢
General Service Large Demand (GSLD-2)	2,000+	$179.19	$7.60	$11.66						0.990¢			0.043¢	3.641¢				
General Service Large Demand-TOU (GSLDT-2)		$179.19			$7.60	$11.66					1.641¢	0.749	0.043¢		4.478¢	3.340¢	5.764¢	2.574¢
Curtailable Service (CS-2)		$179.19	$7.60	$11.66						0.990¢			0.086¢	3.641¢				
Curtailable Service-TOU (CST-2)		$179.19			$7.60	$11.66					1.641¢	0.749	0.086¢		4.478¢	3.340¢	5.764¢	2.574¢
High Load Factor-TOU (2,000 kW or more)		$179.19			$7.83	$11.89			$1.81		0.642¢	0.642	0.043¢		4.478¢	3.340¢	5.764¢	2.574¢
General Service Large Demand (GSLD-3)	2,000+ >69kV	$1,441.86	$6.32	$11.25						0.765¢			0.006¢	3.526¢				
General Service Large Demand-TOU (GSLDT-3)		$1,441.88			$6.32	$11.25					0.864¢	0.729	0.006¢		4.330¢	3.229¢	5.573¢	2.489¢
Curtailable Service (CS-3)		$1,441.86	$6.32	$11.25						0.765¢			0.006¢	3.526¢				
Curtailable Service-TOU (CST-3)		$1,441.88			$6.32	$11.25					0.864¢	0.729	0.006¢		4.330¢	3.229¢	5.573¢	2.489¢
C/I Load Control Program, Transmission [CILC-1(T)]	500+	$1,866.00			$1.29***	$5.53***	$6.79	$11.03			0.712¢	0.712	0.006¢		4.330¢	3.229¢	5.573¢	2.489¢
C/I Load Control Program, Distribution [CILC-1(D)]		$175.00	$3.17*	$3.17*	$1.35***	$5.63***	$7.12	$11.40			0.764¢	0.764	0.042¢		4.472¢	3.336¢	5.757¢	2.571¢

* The higher of current kW demand or the highest demand for the prior 23 months
** 200-499 kW
*** Per kW of on-peak kW less firm kW

JANUARY 2012

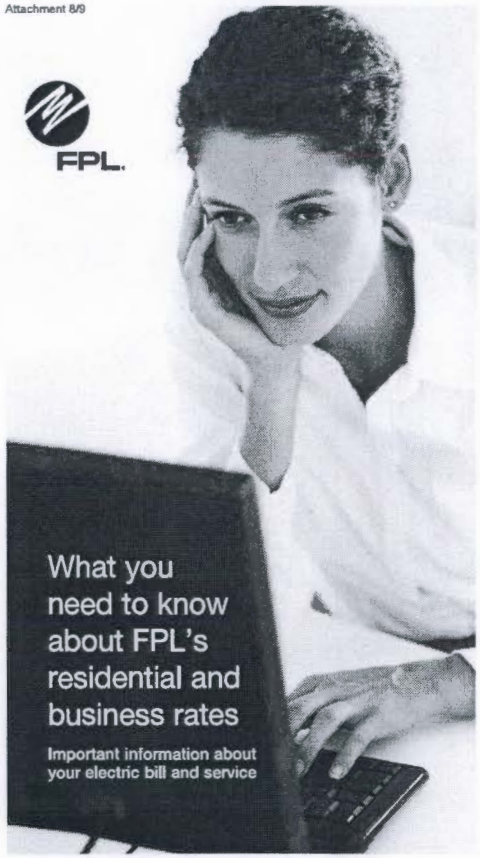
[1] Total demand charges noted above include the applicable capacity payment recovery and energy conservation cost recovery charges per kW, plus the standard demand charge per kW from each rate schedule. For the CILC program, the applicable capacity and energy conservation charges per kW are applied to on-peak and firm kW.

[2] Energy charges noted above include the applicable environmental cost recovery charge per kWh, plus the non-fuel energy charge per kWh for each rate schedule. For RS-1, RST-1, GS-1 and GST-1 rate schedules, energy charges also include the applicable capacity payment recovery and energy conservation cost recovery charges per kWh.

[3] < 1,000 kWh and > 1,000 kWh are applicable only to RS-1 rates.

[4] Nov. 1 - March 31; [5] April 1 - Oct. 31

Note: Rate information is subject to change. In addition, these schedules are subject to applicable franchise charges as well as utility and state sales taxes. kW = kilowatt, kWh = kilowatt-hour



130001 Hearing Exhibit - 00011

This insert includes the latest information about your monthly bill, and explains how our programs can help you manage your electric usage. For more detailed information about the components of your individual residential or business rate, refer to the summary on the back.

Delivering reliable and affordable energy

We're committed to delivering reliable energy you can count on at a great value. FPL customers have an electric bill that's **well** below the national average,* with our typical residential customers and most business customers having the **lowest bill in the state.**** Beyond our efforts to keep your bills low, we offer many ways to help our customers save energy and money through our efficiency programs. If you would like to take control over your energy use and lower your own bill, visit **www.FPL.com/programs** or **www.FPL.com/bizprograms** to learn about our programs and rebates.

** Source for national bill comparisons: Edison Electric Institute Typical Bills and Average Rates Report for Summer 2011, published November 2011.*

*** Source for Florida bill comparisons: Florida Public Service Commission, Florida Municipal Electric Association, Reedy Creek Improvement District, Florida Electric Cooperatives Association and Jacksonville Electric Authority.*

How your rate is determined

Standard residential service – Most residential customers have standard residential service. This includes a price incentive to conserve energy. Electricity usage at or below 1,000 kWh a month is billed at a lower rate.

Business rate classification – Electric rate classification for business customers is based on your maximum monthly electrical usage and when you use electricity. There are multiple business rates available. Qualifying for the right one may produce savings.

Time-of-use rates – If your home or business can shift a significant part of electric usage to off-peak times when the demand for electricity is lower, you may benefit from FPL's time-of-use service. Otherwise, this is not recommended because it could actually increase your bill. With TOU rates, you are billed at a lower rate for off-peak usage and a higher rate for peak-period usage. To benefit, your electrical use must be shifted away from these on-peak hours, Monday through Friday:

- April 1 to Oct. 31, noon to 9 p.m.
- Nov. 1 to March 31, 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m.

Excludes: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day

Visit **www.FPL.com/yourbill** for more information about your bill or to view available business rate options that might be more economical for your business.

Deposits

Our practices regarding deposits ensure that all customers are treated fairly. We may ask customers opening new accounts to pay a deposit for electric service.

Residential – Deposits are based upon the expected cost of two months' electricity at the service address, with a $25 minimum. FPL may waive the deposit if you have an excellent credit score.

If your usage increases and the deposit on hand is less than your two months' average billing, we may ask you to pay the difference in order to bring the deposit to the required level. Additionally, if your account remains open for more than six months, your deposit will earn 6 percent interest from the time the deposit is paid in full. The interest is credited to your account annually. The deposit is returned with any earned interest when the account is closed or after 23 consecutive months of service if:

- You have not paid after the past-due date of your regular bill more than once within the past 12 months, and you have not paid with a check that has been refused by a bank
- Your service has not been disconnected for non-payment within the past 12 months
- You have not used electric service in a fraudulent or unauthorized manner.

Business – You have the choice of paying required deposits with cash or check. Acceptable alternatives to a deposit include an irrevocable bank letter of credit or surety bond. However, these alternatives are only recommended for deposits of more than $1,000 because they are not cost effective for smaller amounts. Deposits are based upon twice the average monthly billing, with a $25 minimum.

For deposits held more than six months, you will earn 6 percent interest from the time the deposit is paid in full, and 7 percent interest for a deposit held 23 continuous months or more, provided a prompt payment record has been maintained for the past 12 months. After six months of service, we may ask you to increase the deposit if the actual average bill amount is higher than projected.

Service charges

The Florida Public Service Commission allows utilities to recover the costs of providing certain services. Current service charges are:

- $14.88 to open/transfer/reopen an account
- $17.66 to reconnect service after disconnection either for non-payment or violation of a rule or regulation
- $23.24 or 5 percent of the payment amount, whichever is greater, for each payment returned by a bank
- 1.5 percent added to overdue bills applied on the past-due balance each month
- $5.11 for each visit by FPL representatives to collect payment on an overdue account.

Gross receipts tax

FPL pays 2.5 percent of gross electric revenues to the state in the form of a gross receipts tax. This tax appears as a separate line item on your bill.

Help for special needs customers

If you have special needs, help is available in case you must evacuate due to extreme weather or other emergency. Your local government has a voluntary registration program for this purpose. To register with your local emergency management office, look under "county government" in your phone directory or call directory assistance.

For more information

- For a complete list of all rates, go to **www.FPL.com/rates**
- Learn how to read your bill at **www.FPL.com/yourbill**
- Residential customers, please call the customer service number on your bill
- Business customers, please call your FPL Account Manager or an FPL representative at 1-800-FPL-5566
- Para ver esta información en español, por favor visite **www.FPL.com/rates**.

130001 Hearing Exhibit - 00012

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

For each type of fuel used for the power generated by the GPIF units dispatched, provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

A.

Please see attached.

FLORIDA POWER & LIGHT COMPANY
DOCKET 130001-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY 3
ATTACHMENT 1 OF 1

FPL does not have the data requested available for 1980 and only partial data available for 1990 as shown.

	1980 ACTUAL				1990* ACTUAL			
	BTU BURNED (MMBtu)	NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF NET GENERATION ($)	BTU BURNED (MMBtu)	NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF NET GENERATION ($)
HEAVY OIL**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LIGHT OIL**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
COAL***	n/a	n/a	n/a	n/a	0	0	0	0
GAS****	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
NUCLEAR***	n/a	n/a	n/a	n/a	98,826,021	8,847,290	11.170	n/a
TOTAL	n/a	n/a	n/a	n/a	221,172,643	21,025,195	10.519	n/a

Source: 1192/GADS

	2000 ACTUAL				2010 ACTUAL			
	BTU BURNED (MMBtu)	NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF NET GENERATION ($)	BTU BURNED (MMBtu)	NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF NET GENERATION ($)
HEAVY OIL**	118,442,619	11,793,033	10.043	497,134,156	0	0	0	0
LIGHT OIL**	14,994	1,735	8.642	76,189	126,587	16,279	7.776	1,778,151
COAL***	48,108,669	4,996,154	9.629	86,197,733	41,567,051	3,886,301	10.696	94,720,481
GAS****	139,653,438	17,492,184	7.984	614,229,961	228,727,720	31,362,775	7.293	1,456,578,640
NUCLEAR***	268,392,688	24,583,722	10.917	82,243,332	249,750,347	22,849,609	10.930	137,029,789
TOTAL	574,612,408	58,866,828	9.761	1,279,881,372	520,171,705	58,114,964	8.951	1,690,107,061

Source: Schedule A4

Source: Schedule A4

	2011 ACTUAL				2012 ACTUAL			
	BTU BURNED (MMBtu)	NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF NET GENERATION ($)	BTU BURNED (MMBtu)	NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF NET GENERATION ($)
HEAVY OIL**	0	0	0	0	0	0	0	0
LIGHT OIL**	104,390	14,013	7.449	1,755,223	158,117	21,378	7.396	2,920,811
COAL***	43,709,813	4,253,247	10.277	104,897,265	36,992,778	3,508,283	10.544	94,781,916
GAS****	258,566,253	35,838,102	7.215	1,509,528,837	251,385,741	35,235,797	7.134	1,248,229,605
NUCLEAR***	241,129,910	21,510,395	11.210	146,597,226	188,199,025	16,915,746	11.126	106,563,067
TOTAL	543,510,366	61,615,758	8.821	1,762,778,552	476,735,661	55,681,204	8.562	1,452,495,399

Source: Schedule A4

Source: Schedule A4

*Prior to 1997, GPIF filings were filed for six-month periods covering October-March and April-September. The period shown for 1990 is the April-September period.

** Distillate & Propane used for firing, hot standby, ignition, prewarming, etc. in fossil steam plants is included in Heavy Oil and Light Oil were applicable.

*** Figures for 1990 are estimates based on ownership share. All other years are based on information reported on Schedule A4.

**** Includes gas used for Fossil Steam Plants start-up were applicable.

n/a: not available. Due to a recent computer data storage equipment failure, availability of historical data requested prior to 2000 is limited.

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

For each type of fuel used for the power generated by all units dispatched (including non-GPIF units), provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

A.

Please see attached.

FLORIDA POWER & LIGHT COMPANY
DOCKET 130001-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY 4
ATTACHMENT 1 OF 1

FPL does not have the data requested available for 1980.

	1980 ACTUAL				1990* ACTUAL			
	BTU BURNED (MMBtu)	SYSTEM NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF SYSTEM NET GENERATION ($)	BTU BURNED (MMBtu)	SYSTEM NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF SYSTEM NET GENERATION ($)
HEAVY OIL**	n/a	n/a	n/a	n/a	117,477,772	11,815,473	9.943	304,440,363
LIGHT OIL**	n/a	n/a	n/a	n/a	1,028,375	70,461	14.595	5,176,628
COAL***	n/a	n/a	n/a	n/a	9,242,940	982,243	9.410	16,697,038
GAS****	n/a	n/a	n/a	n/a	67,045,810	6,277,166	10.681	161,421,755
NUCLEAR***	n/a	n/a	n/a	n/a	98,416,797	8,812,066	11.168	48,921,224
SOLAR	0	0	0	0	0	0	0	0
TOTAL	n/a	n/a	n/a	n/a	293,211,694	27,957,409	10.488	536,657,008

Source: Schedule A3

	2000 ACTUAL				2010 ACTUAL			
	BTU BURNED (MMBtu)	SYSTEM NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF SYSTEM NET GENERATION ($)	BTU BURNED (MMBtu)	SYSTEM NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF SYSTEM NET GENERATION ($)
HEAVY OIL**	235,341,147	23,229,888	10.131	975,779,293	42,914,556	4,081,077	10.515	492,904,740
LIGHT OIL**	2,708,502	192,358	14.081	13,784,489	2,989,828	278,864	10.721	41,380,850
COAL***	66,737,876	6,977,377	9.565	113,732,483	59,019,792	5,721,481	10.315	152,699,819
GAS****	212,298,359	24,217,088	8.766	933,714,908	513,742,638	66,765,651	7.695	3,265,159,503
NUCLEAR***	268,392,688	24,583,722	10.917	82,243,332	249,750,348	22,849,609	10.930	137,029,789
SOLAR	0	0	0	0	0	68,613	0	0
TOTAL	785,478,572	79,200,433	9.918	2,119,254,505	868,417,162	99,765,295	8.705	4,089,174,701

Source: Schedule A3 Source: Schedule A3

	2011 ACTUAL				2012 ACTUAL			
	BTU BURNED (MMBtu)	SYSTEM NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF SYSTEM NET GENERATION ($)	BTU BURNED (MMBtu)	SYSTEM NET GENERATION (MWh)	ANNUAL AVERAGE HEAT RATE (MMBtu/MWh)	FUEL COST OF SYSTEM NET GENERATION ($)
HEAVY OIL**	7,268,455	630,196	11.534	93,949,810	4,479,893	377,641	11.863	61,871,530
LIGHT OIL**	1,909,037	122,987	15.522	37,159,006	418,444	54,367	7.697	8,584,943
COAL***	57,605,124	5,634,006	10.225	163,820,388	49,417,119	4,745,212	10.414	142,583,651
GAS****	564,067,472	74,387,830	7.583	3,289,409,517	603,981,012	80,593,956	7.494	2,999,049,429
NUCLEAR***	241,129,910	22,942,197	10.510	146,597,226	188,199,025	16,915,746	11.126	106,563,067
SOLAR	0	70,687	0	0	0	70,534	0	0
TOTAL	871,979,998	103,787,903	8.402	3,730,935,947	846,495,493	102,757,455	8.238	3,318,652,621

Source: Schedule A3 Source: Schedule A3

*Prior to 1997, fuel filings were filed for six-month periods covering October-March and April-September. The period shown for 1990 is the April-September filing period.

** Distillate & Propane used for firing, hot standby, ignition, prewarming, etc. in fossil steam plants is included in Heavy Oil and Light Oil.

*** Based on ownership share.

**** Includes gas used for Fossil Steam Plants start-up.

n/a: not available. Due to a recent computer data storage equipment failure, availability of historical data requested prior to 2000 is limited.

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the calculations of the maximum potential GPIF incentive amount allowed per 1,000 kWh jurisdictional sales for each year since the implementation of the GPIF. As part of the response, please show the maximum allowed jurisdictional GPIF incentive dollars, jurisdictional sales, and the percentage for heat rate incentive and availability incentive respectively.

A.

Please see attached.

FPL does not have available the information requested prior to October 1997. In addition, the 2012 information was not finalized by the time this response was prepared.

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

OCTOBER, 1997 THROUGH SEPTEMBER, 1998

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 4,734,927,000
LINE 2	MONTH OF October	1997	$ 4,834,923,600
LINE 3	MONTH OF November	1997	$ 4,820,211,400
LINE 4	MONTH OF December	1997	$ 4,813,995,600
LINE 5	MONTH OF January	1998	$ 4,834,363,100
LINE 6	MONTH OF February	1998	$ 4,822,448,000
LINE 7	MONTH OF March	1998	$ 4,822,225,200
LINE 8	MONTH OF April	1998	$ 4,832,859,900
LINE 9	MONTH OF May	1998	$ 4,844,540,800
LINE 10	MONTH OF June	1998	$ 4,862,320,100
LINE 11	MONTH OF July	1998	$ 4,876,981,100
LINE 12	MONTH OF August	1998	$ 4,883,492,300
LINE 13	MONTH OF September	1998	$ 4,877,729,400
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 4,835,462,000
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		60.4525%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 19,996,948
LINE 18	JURISDICTIONAL SALES		83,235,214,000 KWH
LINE 19	TOTAL SALES		84,531,380,000 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.47%
LINE 21*	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 19,690,324
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.24

HEAT RATE PERCENTAGE INCENTIVE	47.3
EAF PERCENTAGE INCENTIVE	52.7

*Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

OCTOBER, 1998 THROUGH DECEMBER, 1998

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 4,877,729,400
LINE 2	MONTH OF October	1998	$ 4,835,283,600
LINE 3	MONTH OF November	1998	$ 4,823,967,600
LINE 4	MONTH OF December	1998	$ 4,803,493,700

LINE 5	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 4 DIVIDED BY 4)	$	4,835,118,000
LINE 6	25 BASIS POINTS		0.0025
LINE 7	REVENUE EXPANSION FACTOR		60.4525%
LINE 8	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 5 TIMES LINE 6 DIVIDED BY LINE 7 TIMES 1/4)	$	4,998,881
LINE 9	JURISDICTIONAL SALES		21,704,331,000 KWH
LINE 10	TOTAL SALES		22,028,470,000 KWH
LINE 11	JURISDICTIONAL SEPARATION FACTOR (LINE 9 DIVIDED BY LINE 10)		98.53%
LINE 12*	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 8 TIMES LINE 11)	$	4,925,325
LINE 13	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 8 DIVIDED BY LINE 11 TIMES 1,000)	$	0.23

HEAT RATE PERCENTAGE INCENTIVE	59.6
EAF PERCENTAGE INCENTIVE	40.4

*Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 1999

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 4,803,493,700	
LINE 2	MONTH OF January	1999	$ 4,836,457,190	
LINE 3	MONTH OF February	1999	$ 4,834,822,663	
LINE 4	MONTH OF March	1999	$ 4,809,576,166	
LINE 5	MONTH OF April	1999	$ 4,833,651,811	
LINE 6	MONTH OF May	1999	$ 4,847,191,302	
LINE 7	MONTH OF June	1999	$ 4,858,920,442	
LINE 8	MONTH OF July	1999	$ 4,877,157,713	
LINE 9	MONTH OF August	1999	$ 4,886,774,844	
LINE 10	MONTH OF September	1999	$ 4,876,019,031	
LINE 11	MONTH OF October	1999	$ 4,835,347,971	
LINE 12	MONTH OF November	1999	$ 4,783,051,829	
LINE 13	MONTH OF December	1999	$ 4,792,763,414	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 4,836,556,005	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4525%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 20,001,472	
LINE 18	JURISDICTIONAL SALES		84,672,515,468	KWH
LINE 19	TOTAL SALES		85,625,161,331	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.89%	
LINE 21*	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 19,778,940	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.23	

HEAT RATE PERCENTAGE INCENTIVE	57.2
EAF PERCENTAGE INCENTIVE	42.8

*Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2000

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 4,792,763,414	
LINE 2	MONTH OF January	2000	$ 4,727,179,660	
LINE 3	MONTH OF February	2000	$ 4,726,828,335	
LINE 4	MONTH OF March	2000	$ 4,700,566,178	
LINE 5	MONTH OF April	2000	$ 4,726,080,486	
LINE 6	MONTH OF May	2000	$ 4,841,034,904	
LINE 7	MONTH OF June	2000	$ 4,853,418,637	
LINE 8	MONTH OF July	2000	$ 4,867,883,837	
LINE 9	MONTH OF August	2000	$ 5,186,617,889	
LINE 10	MONTH OF September	2000	$ 5,169,337,736	
LINE 11	MONTH OF October	2000	$ 5,142,205,512	
LINE 12	MONTH OF November	2000	$ 5,128,151,746	
LINE 13	MONTH OF December	2000	$ 5,032,429,690	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 4,914,961,386	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4594%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 20,323,397	
LINE 18	JURISDICTIONAL SALES		87,959,341,000	KWH
LINE 19	TOTAL SALES		88,929,719,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.91%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 20,101,633	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.23	

HEAT RATE PERCENTAGE INCENTIVE*	50.3
EAF PERCENTAGE INCENTIVE	49.7

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2001

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 5,032,429,690	
LINE 2	MONTH OF January	2001	$ 5,083,457,060	
LINE 3	MONTH OF February	2001	$ 5,063,866,317	
LINE 4	MONTH OF March	2001	$ 5,346,130,086	
LINE 5	MONTH OF April	2001	$ 5,377,658,696	
LINE 6	MONTH OF May	2001	$ 5,390,758,023	
LINE 7	MONTH OF June	2001	$ 5,410,015,639	
LINE 8	MONTH OF July	2001	$ 5,417,401,468	
LINE 9	MONTH OF August	2001	$ 5,433,532,556	
LINE 10	MONTH OF September	2001	$ 5,534,925,777	
LINE 11	MONTH OF October	2001	$ 5,491,382,628	
LINE 12	MONTH OF November	2001	$ 5,469,928,338	
LINE 13	MONTH OF December	2001	$ 5,444,138,876	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 5,345,817,319	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4594%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 22,104,989	
LINE 18	JURISDICTIONAL SALES		90,211,732,000	KWH
LINE 19	TOTAL SALES		91,181,882,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.94%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 21,869,798	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.24	

HEAT RATE PERCENTAGE INCENTIVE*	58.7
EAF PERCENTAGE INCENTIVE	41.3

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2002

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 5,444,138,876	
LINE 2	MONTH OF January	2002	$ 5,483,614,440	
LINE 3	MONTH OF February	2002	$ 5,464,311,451	
LINE 4	MONTH OF March	2002	$ 5,465,713,851	
LINE 5	MONTH OF April	2002	$ 5,236,678,201	
LINE 6	MONTH OF May	2002	$ 5,264,143,052	
LINE 7	MONTH OF June	2002	$ 5,250,553,629	
LINE 8	MONTH OF July	2002	$ 5,266,725,156	
LINE 9	MONTH OF August	2002	$ 5,284,571,716	
LINE 10	MONTH OF September	2002	$ 5,278,515,518	
LINE 11	MONTH OF October	2002	$ 5,140,016,047	
LINE 12	MONTH OF November	2002	$ 5,108,954,003	
LINE 13	MONTH OF December	2002	$ 5,381,760,459	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 5,313,053,569	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4594%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 21,969,510	
LINE 18	JURISDICTIONAL SALES		95,522,890,000	KWH
LINE 19	TOTAL SALES		96,756,048,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.73%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 21,689,508	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.23	

HEAT RATE PERCENTAGE INCENTIVE*	50.0
EAF PERCENTAGE INCENTIVE	50.0

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2003

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 5,381,760,459	
LINE 2	MONTH OF January	2003	$ 5,443,518,178	
LINE 3	MONTH OF February	2003	$ 5,416,795,989	
LINE 4	MONTH OF March	2003	$ 5,420,129,425	
LINE 5	MONTH OF April	2003	$ 5,429,749,346	
LINE 6	MONTH OF May	2003	$ 5,453,701,108	
LINE 7	MONTH OF June	2003	$ 5,460,622,288	
LINE 8	MONTH OF July	2003	$ 5,479,432,897	
LINE 9	MONTH OF August	2003	$ 5,472,758,595	
LINE 10	MONTH OF September	2003	$ 6,070,337,187	
LINE 11	MONTH OF October	2003	$ 6,046,590,185	
LINE 12	MONTH OF November	2003	$ 6,013,601,919	
LINE 13	MONTH OF December	2003	$ 6,004,027,910	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 5,622,540,421	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4594%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 23,249,240	
LINE 18	JURISDICTIONAL SALES		99,495,660,000	KWH
LINE 19	TOTAL SALES		101,006,875,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.50%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 22,901,397	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.23	

HEAT RATE PERCENTAGE INCENTIVE*	49.0
EAF PERCENTAGE INCENTIVE	51.0

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2004

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 6,004,027,910
LINE 2	MONTH OF January	2004	$ 6,024,395,597
LINE 3	MONTH OF February	2004	$ 6,019,783,320
LINE 4	MONTH OF March	2004	$ 6,017,864,767
LINE 5	MONTH OF April	2004	$ 6,059,976,143
LINE 6	MONTH OF May	2004	$ 6,123,002,904
LINE 7	MONTH OF June	2004	$ 6,085,496,844
LINE 8	MONTH OF July	2004	$ 6,181,685,190
LINE 9	MONTH OF August	2004	$ 6,279,107,637
LINE 10	MONTH OF September	2004	$ 6,067,309,873
LINE 11	MONTH OF October	2004	$ 6,148,188,736
LINE 12	MONTH OF November	2004	$ 6,204,255,023
LINE 13	MONTH OF December	2004	$ 6,150,021,001
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 6,105,008,841
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 25,244,250
LINE 18	JURISDICTIONAL SALES		99,094,872,045 KWH
LINE 19	TOTAL SALES		100,626,214,497 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.48%
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 24,860,080
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.25

HEAT RATE PERCENTAGE INCENTIVE*	50.3
EAF PERCENTAGE INCENTIVE	49.7

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2005

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	6,150,021,001
LINE 2	MONTH OF January	2005	$	6,192,687,795
LINE 3	MONTH OF February	2005	$	6,210,102,195
LINE 4	MONTH OF March	2005	$	6,261,225,136
LINE 5	MONTH OF April	2005	$	6,304,149,589
LINE 6	MONTH OF May	2005	$	6,370,481,609
LINE 7	MONTH OF June	2005	$	6,396,241,272
LINE 8	MONTH OF July	2005	$	6,490,766,588
LINE 9	MONTH OF August	2005	$	6,611,466,351
LINE 10	MONTH OF September	2005	$	6,613,215,865
LINE 11	MONTH OF October	2005	$	6,684,550,581
LINE 12	MONTH OF November	2005	$	6,730,591,808
LINE 13	MONTH OF December	2005	$	6,736,887,430
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$	6,442,491,324
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	26,639,743
LINE 18	JURISDICTIONAL SALES			102,296,437,940 KWH
LINE 19	TOTAL SALES			103,802,730,366 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			98.55%
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	26,253,171
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$	0.26

HEAT RATE PERCENTAGE INCENTIVE*	42.0
EAF PERCENTAGE INCENTIVE	58.0

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2006

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 6,736,887,430	
LINE 2	MONTH OF January	2006	$ 6,781,218,339	
LINE 3	MONTH OF February	2006	$ 6,814,949,601	
LINE 4	MONTH OF March	2006	$ 6,859,197,570	
LINE 5	MONTH OF April	2006	$ 6,912,501,792	
LINE 6	MONTH OF May	2006	$ 6,986,198,078	
LINE 7	MONTH OF June	2006	$ 7,041,526,575	
LINE 8	MONTH OF July	2006	$ 7,137,927,980	
LINE 9	MONTH OF August	2006	$ 7,259,570,270	
LINE 10	MONTH OF September	2006	$ 7,369,298,910	
LINE 11	MONTH OF October	2006	$ 7,448,422,300	
LINE 12	MONTH OF November	2006	$ 7,497,921,630	
LINE 13	MONTH OF December	2006	$ 7,539,303,120	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 7,106,532,584	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 28,944,457	
LINE 18	JURISDICTIONAL SALES		103,658,565,540	KWH
LINE 19	TOTAL SALES		105,228,047,611	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.51%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 28,512,748	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.28	

HEAT RATE PERCENTAGE INCENTIVE*	58.1
EAF PERCENTAGE INCENTIVE	41.9

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2007

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 7,539,303,120	
LINE 2	MONTH OF January	2007	$ 7,587,930,090	
LINE 3	MONTH OF February	2007	$ 7,624,550,570	
LINE 4	MONTH OF March	2007	$ 7,315,434,190	
LINE 5	MONTH OF April	2007	$ 7,365,211,380	
LINE 6	MONTH OF May	2007	$ 7,428,938,560	
LINE 7	MONTH OF June	2007	$ 6,776,695,200	
LINE 8	MONTH OF July	2007	$ 6,877,027,010	
LINE 9	MONTH OF August	2007	$ 6,999,230,580	
LINE 10	MONTH OF September	2007	$ 7,102,517,170	
LINE 11	MONTH OF October	2007	$ 7,194,166,590	
LINE 12	MONTH OF November	2007	$ 7,238,128,630	
LINE 13	MONTH OF December	2007	$ 7,275,307,978	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 7,255,726,236	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 29,552,113	
LINE 18	JURISDICTIONAL SALES		105,414,902,346	KWH
LINE 19	TOTAL SALES		106,913,929,150	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.60%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 29,137,766	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.28	

HEAT RATE PERCENTAGE INCENTIVE*	49.6
EAF PERCENTAGE INCENTIVE	50.4

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2008

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	7,275,307,978
LINE 2	MONTH OF January	2008	$	7,317,416,060
LINE 3	MONTH OF February	2008	$	7,346,109,530
LINE 4	MONTH OF March	2008	$	7,333,080,560
LINE 5	MONTH OF April	2008	$	7,380,824,900
LINE 6	MONTH OF May	2008	$	7,449,549,280
LINE 7	MONTH OF June	2008	$	7,549,880,740
LINE 8	MONTH OF July	2008	$	7,637,357,990
LINE 9	MONTH OF August	2008	$	7,741,422,410
LINE 10	MONTH OF September	2008	$	7,938,410,910
LINE 11	MONTH OF October	2008	$	8,034,838,200
LINE 12	MONTH OF November	2008	$	8,071,979,640
LINE 13	MONTH OF December	2008	$	8,089,653,568
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$	7,628,140,905
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			61.3808%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	31,068,934
LINE 18	JURISDICTIONAL SALES			102,918,807,463 KWH
LINE 19	TOTAL SALES			103,911,983,228 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			99.04%
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	30,771,982
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$	0.30

HEAT RATE PERCENTAGE INCENTIVE*	48.1
EAF PERCENTAGE INCENTIVE	51.9

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2009

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	8,089,653,568
LINE 2	MONTH OF January	2009	$	8,133,437,060
LINE 3	MONTH OF February	2009	$	8,167,840,830
LINE 4	MONTH OF March	2009	$	8,016,657,060
LINE 5	MONTH OF April	2009	$	8,072,638,140
LINE 6	MONTH OF May	2009	$	8,134,205,030
LINE 7	MONTH OF June	2009	$	8,104,296,110
LINE 8	MONTH OF July	2009	$	8,203,200,300
LINE 9	MONTH OF August	2009	$	8,315,393,880
LINE 10	MONTH OF September	2009	$	8,250,215,080
LINE 11	MONTH OF October	2009	$	8,340,184,160
LINE 12	MONTH OF November	2009	$	8,404,156,830
LINE 13	MONTH OF December	2009	$	8,435,840,610
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$	8,205,209,128
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			61.3808%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	33,419,282
LINE 18	JURISDICTIONAL SALES			102,754,568,563 KWH
LINE 19	TOTAL SALES			103,909,489,524 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			98.89%
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	33,048,328
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$	0.32

HEAT RATE PERCENTAGE INCENTIVE*	38.3
EAF PERCENTAGE INCENTIVE	61.7

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2010

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 8,435,840,610	
LINE 2	MONTH OF January	2010	$ 8,520,585,620	
LINE 3	MONTH OF February	2010	$ 8,559,232,260	
LINE 4	MONTH OF March	2010	$ 8,626,891,830	
LINE 5	MONTH OF April	2010	$ 8,676,858,880	
LINE 6	MONTH OF May	2010	$ 8,779,206,850	
LINE 7	MONTH OF June	2010	$ 9,026,609,860	
LINE 8	MONTH OF July	2010	$ 9,166,464,440	
LINE 9	MONTH OF August	2010	$ 9,794,978,830	
LINE 10	MONTH OF September	2010	$ 9,609,689,410	
LINE 11	MONTH OF October	2010	$ 9,684,006,840	
LINE 12	MONTH OF November	2010	$ 9,748,604,690	
LINE 13	MONTH OF December	2010	$ 9,790,435,010	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 9,109,185,010	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 37,101,117	
LINE 18	JURISDICTIONAL SALES		104,556,506,000	KWH
LINE 19	TOTAL SALES		106,605,116,877	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.08%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 36,388,776	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.35	

HEAT RATE PERCENTAGE INCENTIVE*	48.4
EAF PERCENTAGE INCENTIVE	51.6

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

CALCULATION OF MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS

JANUARY THROUGH DECEMBER, 2011

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 9,790,435,010	
LINE 2	MONTH OF January	2011	$ 9,478,891,430	
LINE 3	MONTH OF February	2011	$ 9,503,401,243	
LINE 4	MONTH OF March	2011	$ 9,576,318,630	
LINE 5	MONTH OF April	2011	$ 9,634,532,950	
LINE 6	MONTH OF May	2011	$ 9,751,104,180	
LINE 7	MONTH OF June	2011	$ 9,877,440,000	
LINE 8	MONTH OF July	2011	$ 10,141,769,850	
LINE 9	MONTH OF August	2011	$ 10,408,616,650	
LINE 10	MONTH OF September	2011	$ 10,534,065,750	
LINE 11	MONTH OF October	2011	$ 10,619,602,730	
LINE 12	MONTH OF November	2011	$ 10,795,195,300	
LINE 13	MONTH OF December	2011	$ 10,849,749,770	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 10,073,932,576	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 41,030,471	
LINE 18	JURISDICTIONAL SALES		103,327,441,000	KWH
LINE 19	TOTAL SALES		105,503,201,812	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		97.94%	
LINE 21**	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 40,185,243	
LINE 22	MAXIMUM POTENTIAL GPIF INCENTIVE PER 1000 kWh (LINE 21 DIVIDED BY LINE 18 TIMES 1,000)		$ 0.39	

HEAT RATE PERCENTAGE INCENTIVE*	39.4
EAF PERCENTAGE INCENTIVE	60.6

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

**Maximum Allowed Jurisdictional Incentive Dollars are also limited to 50% of fuel savings, no matter what the reward might be on the basis of 25 basis points of ROE

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please describe the various factors that could impact the efficient use of capital and over the long term, rates paid by customers. As part of the response, please provide the fuel and base rates breakdown for 1,000 kWh residential usage, the authorized ROE used to set base rates, the net energy for load, net MWh purchased power, net MWh generation, and T&D loss, for 1980, 1990, 2000, 2010, 2011, and 2012.

A.

FPL's standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate. In cases in which the only competing options are capital investments in new or existing generating units and/or power purchases, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and plans in such generation capital investment cases are comparatively evaluated based on their system cumulative present value revenue requirement (CPVRR).

Consistent with that approach, FPL's decisions on capital investments in generation are based on the results of economic analyses that compare the cost (CPVRR) of the FPL system (owned generation as well as purchased power) over time, under different configurations or strategies, each strategy reflecting the inclusion of, one, or of a combination of, generation alternatives being considered for investment. These comparative analyses take into account the totality of inputs (i.e., system projected load, generation and transmission capital costs, non-fuel O&M, system fuel costs (including fuel transportation costs), system environmental costs, transmission constraints, emission limits, generating unit availabilities and efficiencies, etc.) that indicate how the FPL system would operate in the future. The generation alternative(s) included in the strategy with the lowest system CPVRR is/are generally selected, because investment in such alternative(s) is projected to result in the lowest rates to customers over time, and such investment therefore constitutes an efficient use of capital.

								Distribution Losses	
Year	Authorized ROE used for base rates *	1000 KWH Fuel Residential Rate **	$/1000 KWH Base Rates	Net Energy for Load	Net MWH Purchased Power	System Net MWH generation	Transmission losses	Energy MWH	Demand MW
1980	13.75%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1990	12.80%	19.71	47.38	N/A	N/A	N/A	N/A	N/A	N/A
2000	12%	18.70	43.26	95,989,013	19,375,639	79,200,433	2,275,789	(4,467,404)	(965.82)
2010	10%	38.57	42.00	114,474,633	15,319,657	99,764,318	2,524,588	(4,670,123)	(1,066.64)
2011	10%	39.50	43.03	112,453,554	11,112,848	102,356,101	2,327,465	(4,261,562)	(908.78)
2012	10%	33.43	43.26	110,865,505	8,825,247	102,757,455	2,203,424	***	***

Note: Transmission losses for 2012 are preliminary
* 1980 ROE was approved in PSC Order No. 7843, 1990 ROE was approved in PSC Order No. 22654, 2000 ROE was approved in PSC Order No. 99-0519-AS-EI and 2010-2012 ROE was approved in PSC Order 10-0153-FOF-EI
** Based on rates effective for January. 2011 based on rates effective in March, 2011.
*** 2012 data not available until the end of May, 2013.
N/A: Data is not available

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the projected GPIF heat rate target (Btus per kWh) and the projected MWh net generation of each GPIF unit for the years 2000 through 2012.

A.

Please see attached.

JANUARY THROUGH DECEMBER, 2000

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Cape Canaveral 1	9,511	2,201,000
Cape Canaveral 2	9,690	1,647,000
Lauderdale 4	7,642	3,476,000
Lauderdale 5	7,657	3,466,000
Fort Myers 2	9,321	2,989,000
Manatee 2	10,162	2,000,000
Martin 3	7,206	3,853,000
Martin 4	7,127	3,820,000
Port Everglades 3	9,748	2,134,000
Port Everglades 4	9,664	1,764,000
Putnam 1	8,937	1,694,000
Sanford 4	10,016	1,883,000
Sanford 5	10,290	1,548,000
Turkey Point 3	11,066	5,295,000
Turkey Point 4	11,093	5,310,000
St.Lucie 1	10,854	7,049,000
St.Lucie 2	10,872	5,429,000
Scherer 4	9,989	5,021,000

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2001

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Cape Canaveral 1	9,581	1,983,622
Cape Canaveral 2	9,721	2,007,929
Lauderdale 4	7,610	3,530,878
Lauderdale 5	7,630	3,536,959
Manatee 1	10,066	1,919,212
Manatee 2	10,216	3,533,859
Martin 1	9,734	3,034,494
Martin 2	9,876	2,662,350
Martin 3	7,149	3,603,864
Martin 4	7,069	3,831,437
Port Everglades 3	9,447	2,320,014
Port Everglades 4	9,632	2,510,575
Turkey Point 1	9,319	2,271,637
Turkey Point 3	11,121	5,517,249
Turkey Point 4	11,095	6,003,740
St.Lucie 1	10,817	6,624,422
St.Lucie 2	10,821	5,630,687
Scherer 4	10,043	4,788,089

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2002

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Cape Canaveral 1	9,163	2,300,068
Cape Canaveral 2	9,209	1,553,029
Lauderdale 4	7,645	2,866,302
Lauderdale 5	7,595	2,900,226
Manatee 1	9,861	2,482,706
Manatee 2	10,054	3,399,288
Martin 1	9,147	1,938,634
Martin 2	8,884	3,108,268
Martin 3	7,101	3,482,294
Martin 4	7,004	3,515,966
Port Everglades 3	9,355	1,954,462
Port Everglades 4	9,192	2,069,470
Putnam 1	8,679	1,118,558
Riviera 3	9,809	1,665,641
Riviera 4	9,797	1,547,810
Turkey Point 1	8,960	1,774,562
Turkey Point 2	9,410	1,101,349
Turkey Point 3	11,137	6,003,740
Turkey Point 4	11,079	5,513,318
St. Lucie 1	10,793	6,626,386
St. Lucie 2	10,826	6,140,276
Scherer 4	10,098	4,547,052

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2003

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Cape Canaveral 2	9,030	1,718,337
Lauderdale 4	7,729	2,616,207
Lauderdale 5	7,660	2,975,202
Manatee 2	9,862	2,496,421
Martin 1	9,546	1,888,611
Martin 2	9,590	2,357,272
Martin 3	7,102	2,629,265
Martin 4	7,024	2,415,473
Turkey Point 1	9,128	1,514,164
Turkey Point 2	9,512	2,007,979
Turkey Point 3	11,148	5,500,970
Turkey Point 4	11,119	5,515,004
St. Lucie 1	10,834	7,215,366
St. Lucie 2	10,843	5,639,057
Scherer 4	9,992	4,754,098

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2004

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Cape Canaveral 2	9,528	1,366,108
Lauderdale 4	7,771	2,797,514
Lauderdale 5	7,765	3,010,072
Manatee 1	10,427	2,193,645
Manatee 2	10,384	2,054,592
Martin 1	10,130	2,930,328
Martin 2	10,086	2,928,927
Martin 3	7,160	3,078,007
Martin 4	7,117	3,089,719
Port Everglades 3	9,819	1,736,848
Port Everglades 4	9,859	1,654,443
Scherer 4	10,189	3,886,183
St. Lucie 1	10,860	6,741,236
St. Lucie 2	10,900	5,647,674
Turkey Point 3	11,140	4,950,735
Turkey Point 4	11,134	6,020,517

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2005

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Lauderdale 4	7,815	3,278,217
Lauderdale 5	7,811	2,622,653
Manatee 1	10,274	2,366,608
Manatee 2	10,248	2,625,941
Martin 1	9,994	2,934,991
Martin 2	9,964	3,530,341
Martin 3	7,256	3,092,943
Martin 4	7,203	3,112,541
Scherer 4	10,151	4,536,350
St. Lucie 1	10,846	6,027,256
St. Lucie 2	10,866	6,140,275
Turkey Point 3	11,043	6,003,740
Turkey Point 4	11,078	4,949,673

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2006

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7,073	10,924,512
Lauderdale 4	7,997	2,805,392
Lauderdale 5	7,950	2,860,984
Martin 1	10,011	2,663,251
Martin 2	9,942	2,472,779
Martin 3	7,288	2,483,448
Martin 4	7,228	3,148,555
Sanford 5	7,154	6,784,256
Scherer 4	9,998	4,755,255
St. Lucie 1	10,870	7,219,898
St. Lucie 2	10,931	5,140,112
Turkey Point 3	11,078	5,578,506
Turkey Point 4	11,072	5,585,548

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2007

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7,085	10,033,454
Lauderdale 4	7,954	2,094,764
Lauderdale 5	7,848	2,455,513
Manatee 1	10,220	2,324,325
Martin 1	10,027	2,970,755
Martin 4	7,203	2,096,900
Sanford 4	7,153	7,334,385
Sanford 5	7,117	6,808,879
Scherer 4	10,136	5,217,661
St. Lucie 1	10,961	6,528,213
St. Lucie 2	11,002	4,705,091
Turkey Point 3	11,112	5,517,242
Turkey Point 4	11,120	6,003,732

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2008

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7,079	9,052,636
Lauderdale 4	8,065	3,046,785
Lauderdale 5	7,944	3,041,271
Martin 2	9,892	2,498,162
Martin 3	7,312	2,579,515
Martin 4	7,255	2,241,574
Sanford 4	7,197	6,636,144
Sanford 5	7,192	5,870,531
Scherer 4	10,163	4,893,259
St. Lucie 1	10,881	6,420,882
St. Lucie 2	11,052	6,157,258
Turkey Point 3	11,125	6,020,510
Turkey Point 4	11,070	5,451,815

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2009

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7140	9,034,758
Lauderdale 5	8085	2,238,832
Martin 4	7358	2,141,859
Martin 8	7076	7,018,050
Manatee 3	7255	8,081,494
Sanford 4	7241	4,025,784
Sanford 5	7248	5,711,001
Scherer 4	10193	5,345,965
St. Lucie 1	11006	7,215,359
St. Lucie 2	11272	5,538,810
Turkey Point 3	11476	5,418,757
Turkey Point 4	11488	5,336,552

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2010

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7,230	8,533,858
Martin 8	7,099	8,066,024
Manatee 3	7,020	8,060,864
Sanford 4	7,247	5,833,878
Sanford 5	7,247	4,913,646
Scherer 4	10,151	4,130,961
St. Lucie 1	10,868	6,331,887
St. Lucie 2	11,207	5,223,017
Turkey Point 3	11,474	5,436,159
Turkey Point 4	11,470	6,003,732

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2011

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7,225	8,633,003
Martin 8	7,091	7,179,844
Manatee 3	6,991	7,264,284
Sanford 4	7,273	4,744,682
Sanford 5	7,240	3,950,210
Scherer 4	10,030	4,835,114
St. Lucie 1	11,348	5,083,527
St. Lucie 2	10,822	4,739,036
Turkey Point 3	11,608	6,003,732
Turkey Point 4	11,495	5,104,534
Turkey Point 5	7,017	7,066,465

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2012

GPIF UNIT	ANOHR[1] TARGET BTU/KWH	NET GEN PROJECTION MWH
Ft. Myers 2	7105	7,446,041
Martin 8	7025	8,104,157
Manatee 3	6930	7,820,871
Sanford 4	7252	5,526,062
Scherer 4	9948	4,178,390
St. Lucie 1	10771	6,121,160
St. Lucie 2	10724	4,555,769
Turkey Point 3	10875	3,842,536
Turkey Point 4	11263	5,064,181
Turkey Point 5	6936	7,097,718

(1) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the actual heat rate performance (Btus per kWh) and the actual MWh net generation of each GPIF unit for the years 2000 through 2012.

A.

Please see attached.

JANUARY THROUGH DECEMBER, 2000

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Cape Canaveral 1	9,605	9,541	1,899,129
Cape Canaveral 2	9,811	9,764	1,450,167
Lauderdale 4	7,718	7,587	3,198,076
Lauderdale 5	7,705	7,585	3,151,220
Ft. Myers 2	9,575	9,442	2,117,300
Manatee 2	10,313	10,131	2,685,922
Martin 3	7,054	7,027	3,549,896
Martin 4	6,970	6,959	3,684,384
Port Everglades 3	9,900	9,631	1,884,421
Port Everglades 4	9,937	9,647	1,680,649
Putnam 1	9,005	8,934	1,250,130
Sanford 4	10,537	10,522	1,369,521
Sanford 5	10,293	10,247	1,438,114
Turkey Point 3	11,051	11,095	5,684,312
Turkey Point 4	11,070	11,088	5,591,271
St.Lucie 1	10,763	10,805	7,513,696
St.Lucie 2	10,824	10,837	5,790,487
Scherer 4	10,152	10,036	4,932,497

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2001

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Cape Canaveral 1	9,590	9,524	1,887,154
Cape Canaveral 2	9,508	9,457	1,975,304
Lauderdale 4	7,862	7,756	3,008,923
Lauderdale 5	7,817	7,738	3,046,898
Manatee 1	10,332	10,029	3,369,661
Manatee 2	10,286	10,166	3,027,953
Martin 1	10,132	9,867	3,182,020
Martin 2	10,086	9,950	3,266,542
Martin 3	7,106	7,102	3,431,884
Martin 4	7,016	7,003	3,557,365
Port Everglades 3	9,879	9,441	1,744,455
Port Everglades 4	9,997	9,703	1,889,939
Turkey Point 1	9,742	9,422	1,622,974
Turkey Point 3	11,047	11,079	5,526,117
Turkey Point 4	11,013	11,075	6,105,164
St.Lucie 1	10,788	10,806	6,709,772
St.Lucie 2	10,828	10,831	5,708,076
Scherer 4	10,114	10,020	4,254,665

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2002

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Cape Canaveral 1	9,727	9,207	1,634,579
Cape Canaveral 2	9,661	9,115	1,628,634
Lauderdale 4	7,923	7,808	3,101,178
Lauderdale 5	7,837	7,699	3,130,059
Manatee 1	10,415	9,865	2,868,142
Manatee 2	10,335	10,088	3,247,335
Martin 1	9,990	9,040	2,755,185
Martin 2	10,012	8,914	3,350,998
Martin 3	7,235	7,231	3,588,040
Martin 4	7,308	7,283	3,323,396
Port Everglades 3	9,929	9,388	1,592,035
Port Everglades 4	9,933	9,162	1,565,700
Putnam 1	9,261	8,836	1,124,923
Riviera 3	10,327	9,797	1,199,602
Riviera 4	9,762	9,366	1,250,284
Turkey Point 1	9,783	9,083	1,537,567
Turkey Point 2	9,645	9,332	1,490,711
Turkey Point 3	10,994	11,193	6,215,438
Turkey Point 4	11,069	11,117	5,854,102
St.Lucie 1	10,795	10,811	6,919,395
St.Lucie 2	10,836	10,850	6,318,665
Scherer 4	10,225	10,097	4,005,261

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2003

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Cape Canaveral 2	9,696	9,044	1,705,943
Lauderdale 4	7,922	7,725	2,954,227
Lauderdale 5	7,897	7,713	2,885,590
Manatee 2	10,279	9,888	3,509,452
Martin 1	10,024	9,453	3,072,754
Martin 2	10,047	9,534	2,994,988
Martin 3	7,299	7,287	2,736,957
Martin 4	7,197	7,178	3,027,021
Turkey Point 1	9,691	9,191	1,442,669
Turkey Point 2	9,647	9,424	1,784,043
Turkey Point 3	11,040	11,084	5,445,568
Turkey Point 4	11,083	11,132	5,562,478
St.Lucie 1	10,750	10,824	7,504,813
St.Lucie 2	10,881	10,878	5,010,912
Scherer 4	10,184	9,958	4,592,834

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2004

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Cape Canaveral 2	9,805	9,575	1,297,442
Lauderdale 4	7,968	7,739	2,378,058
Lauderdale 5	7,965	7,880	2,749,770
Manatee 1	10,348	10,416	3,160,741
Manatee 2	10,141	10,212	2,223,488
Martin 1	10,027	10,052	3,157,930
Martin 2	9,895	9,978	3,240,149
Martin 3	7,295	7,291	3,233,487
Martin 4	7,225	7,231	3,321,579
Port Everglades 3	9,979	9,835	1,501,937
Port Everglades 4	9,781	9,713	1,669,060
Scherer 4	10,098	10,121	4,369,415
St.Lucie 1	10,814	10,838	6,324,295
St.Lucie 2	10,885	10,918	5,771,000
Turkey Point 3	11,078	10,987	4,727,354
Turkey Point 4	11,041	11,116	6,079,183

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2005

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Lauderdale 4	8,030	7,878	2,951,457
Lauderdale 5	7,889	7,822	2,333,279
Manatee 1	10,259	10,178	2,088,456
Manatee 2	10,044	9,981	3,432,332
Martin 1	10,106	10,077	2,425,146
Martin 2	9,989	9,930	3,114,076
Martin 3	7,313	7,288	3,123,183
Martin 4	7,273	7,266	2,632,175
Scherer 4	10,178	10,072	4,105,650
St.Lucie 1	10,846	10,876	6,086,163
St.Lucie 2	11,026	10,991	5,346,958
Turkey Point 3	11,025	11,029	5,798,914
Turkey Point 4	11,014	10,947	4,239,374

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2006

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Ft. Myers 2	7,116	7,033	9,813,225
Lauderdale 4	8,162	8,160	2,836,739
Lauderdale 5	7,968	7,989	3,019,523
Martin 1	10,092	10,045	2,581,552
Martin 2	9,970	9,961	2,278,600
Martin 3	7,357	7,343	2,611,701
Martin 4	7,232	7,218	3,138,929
Sanford 5	7,296	7,242	5,647,917
Scherer 4	10,260	10,112	4,211,851
St.Lucie 1	10,770	10,852	7,463,287
St.Lucie 2	11,076	10,845	5,145,090
Turkey Point 3	10,982	11,063	5,581,939
Turkey Point 4	10,990	11,032	5,381,459

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2007

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Ft. Myers 2	7,164	7,156	9,329,632
Lauderdale 4	8,227	8,068	2,103,332
Lauderdale 5	8,142	8,002	2,792,844
Manatee 1	9,855	9,774	1,806,431
Martin 1	10,243	10,218	1,995,338
Martin 4	7,361	7,314	3,033,623
Sanford 4	7,337	7,256	5,896,097
Sanford 5	7,287	7,155	5,953,692
Scherer 4	10,241	10,244	4,915,859
St.Lucie 1	10,809	10,931	6,235,759
St.Lucie 2	11,060	11,103	4,385,829
Turkey Point 3	10,982	11,098	5,148,800
Turkey Point 4	10,979	11,129	6,077,212

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2008

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Ft. Myers 2	7,191	7,138	9,165,030
Lauderdale 4	8,356	8,027	2,406,829
Lauderdale 5	8,208	8,046	2,622,521
Martin 2	9,842	9,729	2,334,538
Martin 3	7,482	7,466	2,597,660
Martin 4	7,393	7,349	2,566,793
Sanford 4	7,373	7,288	5,542,948
Sanford 5	7,395	7,290	5,116,266
Scherer 4	10,023	10,017	4,622,173
St.Lucie 1	10,752	10,830	6,673,041
St.Lucie 2	10,763	10,846	6,031,285
Turkey Point 3	10,969	11,129	6,139,531
Turkey Point 4	10,960	11,049	5,233,334

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2009

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Ft. Myers 2	7,248	7,253	8,981,377
Lauderdale 5	8,170	8,077	2,668,384
Martin 4	7,278	7,320	2,856,218
Martin 8	7,117	7,101	5,625,837
Manatee 3	6,934	6,920	7,252,374
Sanford 4	7,389	7,287	5,317,481
Sanford 5	7,377	7,336	5,618,602
Scherer 4	10,027	10,021	4,689,650
St.Lucie 1	10,753	10,980	7,459,062
St.Lucie 2	10,738	11,029	4,761,937
Turkey Point 3	11,017	11,474	5,244,189
Turkey Point 4	11,069	11,428	5,430,833

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2010

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Ft. Myers 2	7,349	7,367	8,637,392
Martin 8	7,221	7,198	5,899,035
Manatee 3	7,022	6,973	6,200,879
Sanford 4	7,419	7,325	5,405,356
Sanford 5	7,380	7,267	5,274,229
Scherer 4	10,026	9,999	3,918,579
St.Lucie 1	10,887	10,805	5,299,143
St.Lucie 2	10,713	11,157	6,241,447
Turkey Point 3	10,991	11,440	5,355,583
Turkey Point 4	10,960	11,447	5,949,821

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2011

GPIF UNIT	ACTUAL ANOHR[2] BTU/KWH	ADJUSTED[1] ACTUAL ANOHR[2] BTU/KWH	ACTUAL GENERATION MWH
Ft. Myers 2	7,588	7,563	6,924,517
Martin 8	7,079	7,036	6,058,221
Manatee 3	7,128	7,016	5,722,733
Sanford 4	7,393	7,305	5,627,095
Sanford 5	7,403	7,265	5,492,768
Scherer 4	10,148	10,037	4,351,200
St.Lucie 1	10,856	11,268	6,239,174
St.Lucie 2	10,388	10,514	4,143,163
Turkey Point 3	11,001	11,513	5,822,868
Turkey Point 4	10,980	11,476	5,084,741
Turkey Point 5	7,146	7,025	5,745,375

(1) Adjusted Actual ANOHR at target NOF, per GPIF manual page 4.214, is shown here in order to better compare with target ANOHR

(2) With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

JANUARY THROUGH DECEMBER, 2012

FPL did not have this information finalized at the time this response was prepared.

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the projected GPIF Equivalent Availability Factor (EAF) target and the MW capacity of each GPIF unit for the years 2000 through 2012.

A.

Please see attached.

JANUARY THROUGH DECEMBER, 2000

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Cape Canaveral 1	92.4	394
Cape Canaveral 2	78.2	392
Lauderdale 4	93.5	430
Lauderdale 5	93.5	430
Ft. Myers 2	92.7	397
Manatee 2	71.7	798
Martin 3	94.2	450
Martin 4	91.6	450
Port Everglades 3	95.8	390
Port Everglades 4	88.2	402
Putnam 1	91.2	239
Sanford 4	92.3	381
Sanford 5	89.3	381
Turkey Point 3	84.6	693
Turkey Point 4	84.6	693
St.Lucie 1	93.6	839
St.Lucie 2	84.6	714
Scherer 4	94.2	642

JANUARY THROUGH DECEMBER, 2001

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Cape Canaveral 1	84.5	394
Cape Canaveral 2	94.5	394
Lauderdale 4	93.2	422
Lauderdale 5	93.2	422
Manatee 1	78.3	798
Manatee 2	90.1	798
Martin 1	87.7	814
Martin 2	90.9	806
Martin 3	92.5	448
Martin 4	93.1	448
Port Everglades 3	84.5	390
Port Everglades 4	93.7	402
Turkey Point 1	92.4	394
Turkey Point 3	86.0	693
Turkey Point 4	93.6	693
St.Lucie 1	85.7	839
St.Lucie 2	85.7	714
Scherer 4	87.9	642

JANUARY THROUGH DECEMBER, 2002

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Cape Canaveral 1	90.3	394
Cape Canaveral 2	88.2	394
Lauderdale 4	91.8	420
Lauderdale 5	91.9	424
Manatee 1	81.5	788
Manatee 2	85.4	795
Martin 1	89.2	801
Martin 2	90.8	782
Martin 3	94.9	443
Martin 4	87.9	444
Port Everglades 3	94.3	390
Port Everglades 4	86.0	400
Putnam 1	84.7	239
Riviera 3	84.4	278
Riviera 4	93.1	284
Turkey Point 1	85.4	390
Turkey Point 2	94.3	394
Turkey Point 3	93.6	693
Turkey Point 4	86.0	693
St.Lucie 1	86.0	839
St.Lucie 2	93.6	714
Scherer 4	84.4	642

JANUARY THROUGH DECEMBER, 2003

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Cape Canaveral 2	89.5	394
Lauderdale 4	91.7	420
Lauderdale 5	90.3	424
Manatee 2	87.7	795
Martin 1	91.8	801
Martin 2	83.5	782
Martin 3	92.8	443
Martin 4	93.8	444
Turkey Point 1	85.1	390
Turkey Point 2	94.9	394
Turkey Point 3	85.4	693
Turkey Point 4	85.4	693
St.Lucie 1	93.6	839
St.Lucie 2	85.4	714
Scherer 4	93.6	642

JANUARY THROUGH DECEMBER, 2004

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Cape Canaveral 2	89.8	394
Lauderdale 4	79.6	425
Lauderdale 5	89.5	424
Manatee 1	93.7	795
Manatee 2	75.2	795
Martin 1	91.5	803
Martin 2	92.1	796
Martin 3	94.6	435
Martin 4	92.0	436
Port Everglades 3	92.7	381
Port Everglades 4	89.7	388
Scherer 4	84.0	642
St.Lucie 1	86.8	839
St.Lucie 2	85.4	714
Turkey Point 3	75.8	693
Turkey Point 4	93.6	693

JANUARY THROUGH DECEMBER, 2005

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Lauderdale 4	92.7	425
Lauderdale 5	75.5	424
Manatee 1	74.6	788
Manatee 2	96.0	788
Martin 1	76.0	803
Martin 2	92.9	790
Martin 3	92.2	449
Martin 4	92.5	450
Scherer 4	95.5	621
St.Lucie 1	77.2	839
St.Lucie 2	93.6	714
Turkey Point 3	93.6	693
Turkey Point 4	75.8	693

JANUARY THROUGH DECEMBER, 2006

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	93.1	1,423
Lauderdale 4	93.3	425
Lauderdale 5	92.9	424
Martin 1	90.8	803
Martin 2	84.5	790
Martin 3	73.0	449
Martin 4	90.8	450
Sanford 5	91.3	950
Scherer 4	85.9	621
St.Lucie 1	93.6	839
St.Lucie 2	75.8	714
Turkey Point 3	86.0	693
Turkey Point 4	86.8	693

JANUARY THROUGH DECEMBER, 2007

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	78.9	1,390
Lauderdale 4	82.6	423
Lauderdale 5	92.2	433
Manatee 1	86.6	791
Martin 1	94.6	803
Martin 4	94.0	427
Sanford 4	90.2	920
Sanford 5	91.3	916
Scherer 4	96.0	621
St.Lucie 1	84.0	839
St.Lucie 2	70.3	714
Turkey Point 3	84.2	693
Turkey Point 4	90.7	693

JANUARY THROUGH DECEMBER, 2008

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	86.6	1,373
Lauderdale 4	93.3	434
Lauderdale 5	91.9	432
Martin 2	94.9	795
Martin 3	93.8	413
Martin 4	82.4	427
Sanford 4	94.1	898
Sanford 5	85.5	894
Scherer 4	85.6	621
St.Lucie 1	82.4	839
St.Lucie 2	93.6	714
Turkey Point 3	90.9	693
Turkey Point 4	81.7	693

JANUARY THROUGH DECEMBER, 2009

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	89.7	1,333
Lauderdale 5	93.5	433
Martin 4	92.0	426
Martin 8	83.2	1,035
Manatee 3	92.7	1,043
Sanford 4	90.2	891
Sanford 5	88.4	885
Scherer 4	96.0	624
St.Lucie 1	93.6	839
St.Lucie 2	81.8	714
Turkey Point 3	82.7	693
Turkey Point 4	81.3	693

JANUARY THROUGH DECEMBER, 2010

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	92.7	1,330
Martin 8	85.5	1,031
Manatee 3	94.3	1,041
Sanford 4	89.7	885
Sanford 5	88.2	883
Scherer 4	74.4	625
St.Lucie 1	81.3	839
St.Lucie 2	76.7	714
Turkey Point 3	82.3	693
Turkey Point 4	93.6	693

JANUARY THROUGH DECEMBER, 2011

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	84.0	1,330
Martin 8	81.3	1,031
Manatee 3	84.9	1,041
Sanford 4	93.7	885
Sanford 5	94.4	883
Scherer 4	85.9	651
St.Lucie 1	63.5	839
St.Lucie 2	66.8	714
Turkey Point 3	93.2	693
Turkey Point 4	78.5	693
Turkey Point 5	90.7	1,045

JANUARY THROUGH DECEMBER, 2012

GPIF UNIT	EAF TARGET (%)	MW CAPACITY
Ft. Myers 2	91.6	1,330
Martin 8	91.4	1,057
Manatee 3	93.9	1,041
Sanford 4	92.5	897
Scherer 4	72.5	651
St.Lucie 1	68.7	968
St.Lucie 2	60.1	714
Turkey Point 3	49.9	809
Turkey Point 4	78.0	809
Turkey Point 5	92.6	1,036

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the actual GPIF Equivalent Availability Factor (EAF) performance and the MW capacity for each GPIF unit for the years 2000 through 2012.

A.

Please see attached.

JANUARY THROUGH DECEMBER, 2000

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Cape Canaveral 1	90.8	90.8	394
Cape Canaveral 2	77.0	77.2	392
Lauderdale 4	91.1	91.3	430
Lauderdale 5	89.8	89.9	430
Ft. Myers 2	88.9	88.9	397
Manatee 2	80.4	81.1	798
Martin 3	92.8	95.3	450
Martin 4	96.9	95.3	450
Port Everglades 3	94.6	94.6	390
Port Everglades 4	83.5	83.7	402
Putnam 1	96.4	92.9	239
Sanford 4	90.8	90.8	381
Sanford 5	91.8	91.8	381
Turkey Point 3	91.2	90.1	693
Turkey Point 4	89.9	89.2	693
St.Lucie 1	100.0	100.0	839
St.Lucie 2	91.1	90.3	714
Scherer 4	98.0	98.0	642

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2001

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Cape Canaveral 1	82.6	83.3	394
Cape Canaveral 2	91.5	91.5	394
Lauderdale 4	93.4	93.7	422
Lauderdale 5	93.3	93.6	422
Manatee 1	93.4	80.1	798
Manatee 2	82.9	95.5	798
Martin 1	94.5	90.6	814
Martin 2	94.3	94.3	806
Martin 3	91.0	95.8	448
Martin 4	98.0	97.7	448
Port Everglades 3	84.6	85.4	390
Port Everglades 4	95.3	95.3	402
Turkey Point 1	96.9	96.9	394
Turkey Point 3	89.2	89.4	693
Turkey Point 4	98.1	98.4	693
St.Lucie 1	89.8	89.6	839
St.Lucie 2	90.2	89.0	714
Scherer 4	84.3	87.8	642

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2002

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Cape Canaveral 1	90.8	90.8	394
Cape Canaveral 2	85.7	85.6	394
Lauderdale 4	94.3	94.4	420
Lauderdale 5	93.6	93.4	424
Manatee 1	93.6	89.8	788
Manatee 2	94.1	90.1	795
Martin 1	78.5	80.2	801
Martin 2	93.3	89.5	782
Martin 3	95.5	96.3	443
Martin 4	89.2	94.2	444
Port Everglades 3	88.8	92.3	390
Port Everglades 4	89.4	90.7	400
Putnam 1	89.7	86.9	239
Riviera 3	92.4	96.3	278
Riviera 4	78.1	96.5	284
Turkey Point 1	96.3	89.2	390
Turkey Point 2	87.6	98.7	394
Turkey Point 3	99.6	100.0	693
Turkey Point 4	94.4	91.6	693
St.Lucie 1	92.5	91.7	839
St.Lucie 2	99.7	100.0	714
Scherer 4	83.6	83.2	642

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2003

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Cape Canaveral 2	83.2	89.5	394
Lauderdale 4	91.5	93.3	420
Lauderdale 5	91.5	92.7	424
Manatee 2	98.7	91.1	795
Martin 1	89.2	95.9	801
Martin 2	89.4	86.9	782
Martin 3	78.1	77.0	443
Martin 4	84.4	88.1	444
Turkey Point 1	78.5	86.3	390
Turkey Point 2	93.3	93.3	394
Turkey Point 3	87.6	88.0	693
Turkey Point 4	89.8	91.8	693
St.Lucie 1	100.0	100.0	839
St.Lucie 2	80.0	85.6	714
Scherer 4	93.9	93.9	642

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2004

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Cape Canaveral 2	89.9	89.9	394
Lauderdale 4	76.2	82.7	425
Lauderdale 5	90.7	93.2	424
Manatee 1	96.8	96.8	795
Manatee 2	73.7	75.6	795
Martin 1	92.1	92.1	803
Martin 2	94.9	94.9	796
Martin 3	94.7	95.1	435
Martin 4	96.1	92.3	436
Port Everglades 3	89.1	94.4	381
Port Everglades 4	89.1	92.4	388
Scherer 4	87.3	86.9	642
St.Lucie 1	90.0	93.0	839
St.Lucie 2	89.8	90.0	714
Turkey Point 3	76.2	76.6	693
Turkey Point 4	97.5	97.7	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2005

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Lauderdale 4	95.3	94.3	425
Lauderdale 5	74.7	79.2	424
Manatee 1	70.9	75.2	788
Manatee 2	94.9	94.9	788
Martin 1	72.8	78.1	803
Martin 2	94.1	94.1	790
Martin 3	92.5	92.7	449
Martin 4	76.7	94.8	450
Scherer 4	98.0	98.0	621
St.Lucie 1	83.7	83.5	839
St.Lucie 2	87.2	98.7	714
Turkey Point 3	94.5	94.7	693
Turkey Point 4	69.5	69.6	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2006

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Ft. Myers 2	92.4	92.4	1,423
Lauderdale 4	94.2	96.1	425
Lauderdale 5	99.0	96.3	424
Martin 1	94.2	94.2	803
Martin 2	83.7	85.0	790
Martin 3	81.8	77.7	449
Martin 4	94.4	94.9	450
Sanford 5	82.9	83.7	950
Scherer 4	88.3	88.3	621
St.Lucie 1	99.6	99.9	839
St.Lucie 2	83.2	80.9	714
Turkey Point 3	89.4	91.3	693
Turkey Point 4	86.3	89.7	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2007

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Ft. Myers 2	90.6	85.2	1,390
Lauderdale 4	72.0	83.6	423
Lauderdale 5	93.1	94.6	433
Manatee 1	89.0	88.6	791
Martin 1	87.6	87.6	803
Martin 4	92.8	92.8	427
Sanford 4	90.1	91.8	920
Sanford 5	92.3	91.5	916
Scherer 4	95.7	95.7	621
St.Lucie 1	83.7	89.8	839
St.Lucie 2	71.0	70.3	714
Turkey Point 3	82.5	84.4	693
Turkey Point 4	97.2	99.9	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2008

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Ft. Myers 2	88.7	91.0	1,373
Lauderdale 4	87.3	89.5	434
Lauderdale 5	92.9	93.4	432
Martin 2	92.0	92.9	795
Martin 3	81.8	83.5	413
Martin 4	81.2	83.8	427
Sanford 4	93.8	94.0	898
Sanford 5	91.1	92.5	894
Scherer 4	89.4	88.2	621
St.Lucie 1	88.9	87.0	839
St.Lucie 2	94.5	94.8	714
Turkey Point 3	97.8	97.8	693
Turkey Point 4	83.4	85.5	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2009

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Ft. Myers 2	91.4	92.4	1,333
Lauderdale 5	95.4	95.7	433
Martin 4	91.3	92.7	426
Martin 8	79.0	81.1	1,035
Manatee 3	93.7	94.2	1,043
Sanford 4	88.0	88.2	891
Sanford 5	94.0	93.0	885
Scherer 4	95.6	95.6	624
St.Lucie 1	99.4	99.5	839
St.Lucie 2	74.9	75.1	714
Turkey Point 3	84.2	84.7	693
Turkey Point 4	87.6	88.8	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2010

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Ft. Myers 2	92.0	90.7	1,330
Martin 8	87.4	91.4	1,031
Manatee 3	88.3	94.8	1,041
Sanford 4	91.0	92.2	885
Sanford 5	91.9	90.9	883
Scherer 4	78.4	77.1	625
St.Lucie 1	72.6	79.5	839
St.Lucie 2	97.5	83.1	714
Turkey Point 3	85.8	87.5	693
Turkey Point 4	95.0	95.5	693

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2011

GPIF UNIT	ACTUAL EAF	ADJUSTED[1] ACTUAL EAF	MW CAPACITY
Ft. Myers 2	82.1	84.3	1,330
Martin 8	81.9	82.3	1,031
Manatee 3	77.4	78.1	1,041
Sanford 4	92.6	96.8	885
Sanford 5	94.4	94.4	883
Scherer 4	91.0	87.3	651
St.Lucie 1	84.0	66.7	839
St.Lucie 2	63.1	68.8	714
Turkey Point	93.4	93.4	693
Turkey Point	81.5	82.1	693
Turkey Point	87.0	87.2	1,045

(1) Adjusted Actual EAF, per GPIF manual page 4.213, is shown here in order to better compare with target EAF

JANUARY THROUGH DECEMBER, 2012

FPL did not have this information finalized at the time this response was prepared.

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please describe the improvement or decline in your company's heat rate performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:
(a) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89;

(b) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1990-99;

(c) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2000-09;

(d) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2010-12;

e) The amount of capital and O&M required and deployed for the heat rate improvement in each period;

(f) The amount of net GPIF incentive payments for the heat rate performance in each period (annual and cumulative);

(g) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1980-89;

(h) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1990-99;

(i) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2000-09;

(j) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2010-12;

(k) The alternative analysis (if any).

A.

(a) FPL does not have the information necessary to calculate the annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89.

(b)

PERIOD 1990-1999

	Actual Weighted* ANOHR for Base Load (GPIF) Units	Annual Rate of Change	Fuel Savings/(Loss)**
1990	10,390	n/a	n/a
1991	10,133	-2.5%	n/a
1992	10,338	2.0%	n/a
1993	10,242	-0.9%	n/a
1994	10,266	0.2%	n/a
1995	9,919	-3.4%	n/a
1996	9,564	-3.6%	n/a
1997	9,645	0.8%	n/a
1998	9,634	-0.1%	n/a
1999	9,716	0.8%	n/a
Annual average rate of change		-0.7%	n/a

*Weighted by actual net MWh generation excluding estimated generation not owned by FPL for co-owned units
** FPL does not have this information available
Since a decrease in heat rate signifies improvement, a negative rate of change represents improved heat rate performance

Prior to 1997, GPIF filings were filed for six-month periods covering October-March and April-September. Rather than combining two different six-month filings into one to arrive at an annual filing, FPL analysis covers the following periods:
The 1990-1996 ANOHR is for the filing period April-Sept of the corresponding year
The 1997 ANOHR is from the filing period Oct. '96 - Sept '97
The 1998 ANOHR is from the filing period Oct. '97 - Sept '98
The 1999 ANOHR is from the filing period Jan-Dec 1999

(C)

PERIOD 2000-2009

	Actual Weighted* ANOHR** for Base Load (GPIF) Units	Annual Rate of Change	Fuel Savings/(Loss)***
2000	9,755	n/a	n/a
2001	9,829	0.8%	n/a
2002	9,875	0.5%	n/a
2003	9,891	0.2%	n/a
2004	9,895	0.0%	n/a
2005	9,921	0.3%	n/a
2006	9,210	-7.2%	n/a
2007	9,110	-1.1%	n/a
2008	9,096	-0.2%	n/a
2009	8,725	-4.1%	n/a
Annual average rate of change		-1.2%	n/a

*Weighted by actual net MWh generation excluding estimated generation not owned by FPL for co-owned units

**With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

*** FPL does not have this information available. See response to 11k for alternative analysis
Since a decrease in heat rate signifies improvement, a negative rate of change represents improved heat rate performance

(d)

PERIOD 2010-2012

	Actual Weighted* ANOHR** for Base Load (GPIF) Units	Annual Rate of Change	Fuel Savings/(Loss)***
2010	8,878	n/a	n/a
2011	8,730	-1.7%	n/a
2012****			
Annual average rate of change		-1.7%	n/a

*Weighted by actual net MWh generation excluding estimated generation not owned by FPL for co-owned units

**With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

*** FPL does not have this information available

**** FPL did not have this information finalized at the time this response was prepared

Since a decrease in heat rate signifies improvement, a negative rate of change represents improved heat rate performance

(e) FPL cannot differentiate the amount of capital and O&M required and deployed for the heat rate improvement in each period because FPL's financial systems do not capture data on expenditures specific to this metric.

(f)

Net GPIF Incentive/(Penalty) for Heat Rate Performance

1980	N/A	1990	N/A	2000	$ 32,258	2010	$ (2,393,654)
1981	N/A	1991	N/A	2001	$ (541,060)	2011	$ 49,829
1982	N/A	1992	N/A	2002	$ (1,113,279)	2012	Not available at the time of this filing
1983	N/A	1993	N/A	2003	$ (512,294)		
1984	N/A	1994	N/A	2004	$ 431,309		
1985	N/A	1995	N/A	2005	$ 1,418,454		
1986	N/A	1996	N/A	2006	$ (958,281)		
1987	N/A	Oct 97-Sep 98	$ (43,648)	2007	$ (2,314,204)		
1988	N/A	Oct 98 - Dec 98	$ 30,170	2008	$ (651,462)		
1989	N/A	1999	$ (700,649)	2009	$ 1,243,608		
Total Period	N/A		N/A		$ (2,964,951)		N/A

(g) FPL does not have the information necessary to calculate the annual average rate of change in the composite heat rate target set by the GPIF in the period of 1980-89.

(h) FPL does not have the generation projections necessary to calculate the annual average rate of change in the composite heat rate target set by the GPIF in the period of 1990-99 .

(i)

PERIOD 2000-2009

	Target Weighted* ANOHR** for Base Load (GPIF) Units	Annual Rate of Change
2000	9,643	n/a
2001	9,683	0.4%
2002	9,604	-0.8%
2003	9,793	2.0%
2004	9,901	1.1%
2005	9,878	-0.2%
2006	9,114	-7.7%
2007	9,063	-0.6%
2008	9,038	-0.3%
2009	8,897	-1.6%
Annual average rate of change		-0.9%

*Weighted by net MWh generation projection excluding estimated generation not owned by FPL for co-owned units

**With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

Since a decrease in heat rate signifies improvement, a negative rate of change represents improved heat rate performance

(j)

PERIOD 2010-2012

	Target Weighted* ANOHR** for Base Load (GPIF) Units	Annual Rate of Change
2010	8,858	n/a
2011	8,708	-1.7%
2012	8,510	-2.3%

Annual average rate of change -2.0%

*Weighted by net MWh generation projection excluding estimated generation not owned by FPL for co-owned units

**With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

Since a decrease in heat rate signifies improvement, a negative rate of change represents improved heat rate performance

(k) The intent of the GPIF is not to reward or penalize utilities due to long-term improvement or degradation in system efficiency but rather to reward or penalize for a unit based on how the unit performs relative to its target for each specific year, with the targets set on the basis of recent historical performance. Hence, savings realized through the GPIF are not associated with the long-term improvement of the generating fleet; rather, they are realized from the performance improvement of each GPIF unit compared to its expected performance for a given year. Consequently, there is no direct correlation between a year-over-year rate of change in heat rate or availability of a fleet of GPIF units and the individual fuel savings or losses associated with a specific unit in a year.

An alternate analysis is shown below to accurately demonstrate how the change in heat rate performance of a GPIF unit relative to its target for a given year is directly related to the fuel savings or losses realized by that unit for the given year.

For this analysis, Martin 4 was chosen since this unit was a GPIF unit throughout the whole decade

	Martin 4 ANOHR* Target	Martin 4 Adjusted[(1)] Actual ANOHR*	Actual Vs Target Difference	% Change	Fuel** Savings/(Losses) $000
2000	7,127	6,959	-168	-2.4%	896
2001	7,069	7,003	-66	-0.9%	0
2002	7,004	7,283	279	4.0%	(1,602)
2003	7,024	7,178	154	2.2%	(764)
2004	7,117	7,231	114	1.6%	(626)
2005	7,203	7,266	63	0.9%	0
2006	7,228	7,218	-10	-0.1%	0
2007	7,203	7,314	111	1.5%	(2,029)
2008	7,255	7,349	94	1.3%	(1,089)
2009	7,358	7,320	-38	-0.5%	0

(1) Adjusted Actual ANOHR at target NOF as prescribed by the GPIF manual page 4.214

*With Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI

** Due to the GPIF +/-75 Btu/KWh ANOHR dead band, when actual performance is within this dead band from the target, no fuel savings/losses are credited.

Since a decrease in heat rate signifies improvement, a negative % change represents improved heat rate performance

Q.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please describe the improvement or decline in your company's availability performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

(a) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89;

(b) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1990-99;

(c) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2000-09;

(d) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2010-12;

(e) The amount of capital and O&M required and deployed for the improvement in each period;

(f) The amount of net GPIF incentive payments for the availability factor performance in each period (annual and cumulative);

(g) The annual average rate of change in the composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1980-89;

(h) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1990-99;

(i) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2000-09;

(j) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2010-12;

(k) The alternative analysis (if any).

A.

(a) FPL does not have the information necessary to calculate the annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89.

(b)

PERIOD 1990-1999

	Actual Weighted* EAF for Base Load (GPIF) Units	Annual Rate of Change	Fuel Savings/(Loss)**
1990	78.7	n/a	n/a
1991	83.4	6.0%	n/a
1992	82.5	-1.2%	n/a
1993	86.1	4.4%	n/a
1994	89.4	3.8%	n/a
1995	90.4	1.1%	n/a
1996	86.0	-4.9%	n/a
1997	91.4	6.3%	n/a
1998	91.5	0.1%	n/a
1999	91.8	0.3%	n/a
Annual average rate of change		1.8%	n/a

*Weighted by MW capacity excluding capacity not owned by FPL for co-owned units
** FPL does not have this information available

Prior to 1997, GPIF filings were filed for six-month periods covering October-March and April-September. Rather than combining two different six-month filings into one to arrive at an annual filing, FPL analysis covers the following periods:
The 1990-1996 ANOHR is for the filing period April-Sept of the corresponding year
The 1997 ANOHR is from the filing period Oct. '96 - Sept '97
The 1998 ANOHR is from the filing period Oct. '97 - Sept '98
The 1999 ANOHR is from the filing period Jan-Dec 1999

(c)

PERIOD 2000-2009

	Actual Weighted* EAF for Base Load (GPIF) Units	Annual Rate of Change	Fuel Savings/(Loss)**
2000	91.0	n/a	n/a
2001	91.2	0.2%	n/a
2002	91.4	0.2%	n/a
2003	89.5	-2.1%	n/a
2004	89.0	-0.6%	n/a
2005	84.8	-4.7%	n/a
2006	89.8	5.9%	n/a
2007	87.9	-2.1%	n/a
2008	90.0	2.4%	n/a
2009	89.4	-0.7%	n/a
Annual average rate of change		-0.2%	n/a

*Weighted by MW capacity excluding capacity not owned by FPL for co-owned units

** FPL does not have this information available. See response to 12k for alternative analysis

(d)

PERIOD 2010-2012

	Actual Weighted* EAF for Base Load (GPIF) Units	Annual Rate of Change	Fuel Savings/(Loss)**
2010	88.3	n/a	n/a
2011***	84.3	-4.5%	n/a
2012****			
Annual average rate of change		-4.5%	n/a

*Weighted by MW capacity excluding capacity not owned by FPL for co-owned units
** FPL does not have this information available
*** Reflects planned outages for unit uprates
****FPL did not have this information finalized at the time this response was prepared

(e) FPL cannot differentiate the amount of capital and O&M required and deployed for the availability factor improvement in each period because FPL's financial systems do not capture data on expenditures specific to this metric.

(f)

Net GPIF Incentive/(Penalty) for EAF Performance

1980	N/A	1990	N/A	2000	$ 8,898,409	2010	$ 8,965,103
1981	N/A	1991	N/A	2001	$ 7,584,019	2011	$ 7,654,083
1982	N/A	1992	N/A	2002	$ 8,583,217	2012	Not available at the time of this filing
1983	N/A	1993	N/A	2003	$ 7,103,763		
1984	N/A	1994	N/A	2004	$10,283,203		
1985	N/A	1995	N/A	2005	$ 7,029,551		
1986	N/A	1996	N/A	2006	$ 9,860,975		
1987	N/A	Oct 97-Sep 98	$ 9,713,342	2007	$ 7,653,459		
1988	N/A	Oct 98 - Dec 98	$ 1,667,203	2008	$12,176,564		
1989	N/A	1999	$ 7,674,399	2009	$ 7,547,576		
Total Period	N/A		N/A		$86,720,737		N/A

(g) FPL does not have the information necessary to calculate the annual average rate of change in the composite availability factor target set by the GPIF in the period of 1980-89.

(h)

PERIOD 1990-1999

	Target Weighted* EAF for Base Load (GPIF) Units	Annual Rate of Change
1990	83.1	n/a
1991	83.6	0.6%
1992	82.5	-1.4%
1993	85.0	3.1%
1994	88.8	4.5%
1995	91.3	2.8%
1996	85.6	-6.3%
1997	86.1	0.5%
1998	88.7	3.1%
1999	90.0	1.4%
Annual average rate of change		0.9%

*Weighted by MW capacity excluding capacity not owned by FPL for co-owned units

Prior to 1997, GPIF filings were filed for six-month periods covering October-March and April-September. Rather than combining two different six-month filings into one to arrive at an annual filing, FPL analysis covers the following periods:
The 1990-1996 EAF is for the filing period April-Sept of the corresponding year
The 1997 EAF is from the filing period Oct. '96 - Sept '97
The 1998 EAF is from the filing period Oct. '97 - Sept '98
The 1999 EAF is from the filing period Jan-Dec 1999

(i)

PERIOD 2000-2009

	Target Weighted* EAF for Base Load (GPIF) Units	Annual Rate of Change
2000	88.4	n/a
2001	88.7	0.3%
2002	88.7	0.0%
2003	89.3	0.7%
2004	87.5	-2.0%
2005	86.3	-1.4%
2006	88.1	2.1%
2007	86.6	-1.7%
2008	88.7	2.4%
2009	88.6	-0.1%
Annual average rate of change		0.0%

*Weighted by MW capacity excluding capacity not owned by FPL for co-owned units

(j)

PERIOD 2010-2012

	Target Weighted* EAF for Base Load (GPIF) Units	Annual Rate of Change
2010	86.8	n/a
2011**	83.7	-3.6%
2012**	81.1	-3.1%

Annual average rate of change -3.4%

*Weighted by MW capacity excluding capacity not owned by FPL for co-owned units
** Reflects planned outages for unit uprates

(k) The intent of the GPIF is not to reward or penalize utilities due to long-term improvement or degradation in system efficiency but rather to reward or penalize for a unit based on how the unit performs relative to its target for each specific year, with the targets set on the basis of recent historical performance. Hence, savings realized through the GPIF are not associated with the long-term improvement of the generating fleet; rather, they are realized from the performance improvement of each GPIF unit compared to its expected performance for a given year. Consequently, there is no direct correlation between a year-over-year rate of change in heat rate or availability of a fleet of GPIF units and the individual fuel savings or losses associated with a specific unit in a year.

An alternate analysis is shown below to accurately demonstrate how the change in EAF performance of a GPIF unit relative to its target for a given year is directly related to the fuel savings or losses realized by that unit for the given year.

For this analysis, Martin 4 was chosen since this unit was a GPIF unit throughout the whole decade.

	Martin 4 EAF Target	Martin 4 Adjusted[1] Actual EAF	Actual Vs Target Difference	% Change	Fuel Savings/(Losses) $000
2000	91.6	95.3	3.6	4.0%	467
2001	93.1	97.7	4.6	4.9%	673
2002	87.9	94.2	6.3	7.1%	966
2003	93.8	88.1	-5.7	-6.1%	(601)
2004	92.0	92.3	0.3	0.3%	49
2005	92.5	94.8	2.3	2.5%	723
2006	90.8	94.9	4.1	4.5%	876
2007	94.0	92.8	-1.2	-1.3%	(693)
2008	82.4	83.8	1.4	1.7%	796
2009	92.0	92.7	0.7	0.8%	812

(1) Per GPIF manual page 4.213, Equivalent Availability adjustment due to planned outage actual duration versus targeted duration

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 6th day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Terry Keith, who is personally known to me, and he acknowledged before me that he cosponsored the answer to interrogatory number 6 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-12) in Docket No. 130001-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of March, 2013.

Terry Keith

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lily A Rodriguez
My Commission EE 875512
Expires 02/17/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 4th day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Carine Bullock, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 3 through 5, and 7 through 12 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-12) in Docket No. 130001-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of March, 2013.

Carine Bullock

JAYNE LORING DAVIS
MY COMMISSION # DD908031
EXPIRES September 14, 2013
(407) 398-0153 FloridaNotaryService.com

Jayne Loring Davis

Notary Public
State of Florida, at Large

My Commission Expires: 9-14-13

55

FPL's Responses to Staff's Second Set of Interrogatories (Nos. 13-23)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 55
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0110-0129]

Q.

For each Request for Proposal (RFP) for coal that Georgia Power Company/Southern Company Services issued in 2012 for Florida Power and Light's (FPL) interest in Scherer Unit 4, please provide the following information:

a) List the bids received. Include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

b) Describe what action was taken for each RFP. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A.

a) Georgia Power Company/Southern Company Services issued four (4) RFPs in 2012 for spot coal to supply Plant Scherer in the 3rd quarter, 4th quarter & December of 2012 and the 1st quarter of 2013. The suppliers, tonnage bid, coal quality and delivered price information are listed in Attachment I to this answer.

All coal delivered to Plant Scherer is by rail in unit trains of 124 rapid discharge railcars. The Burlington Northern Santa Fe (BNSF) Railroad serves all coal mines located in Wyoming's Powder River Basin (PRB). Loaded trains are routed to Scherer via Memphis, TN. The Norfolk Southern Railroad (NS) accepts the trains from BNSF, in Memphis, for final delivery to the plant.

b) All bids were evaluated on a delivered cost per million btu basis.

No purchases were made from the bids solicited for the 3rd quarter of 2012.

Twenty trains, approximately 292,000 tons, were purchased from [redacted], the low evaluated bidder, from the offers for the 4th quarter of 2012. Approximately 191,000 tons, of the total purchase, were for FPL.

No purchases were made from the bids solicited for December of 2012.

Twenty-one trains, approximately 304,000 tons, were purchased from [redacted], the low evaluated bidder, from the offers for the 1st quarter of 2013. Approximately 247,000 tons, of the total purchase, were for FPL.

Florida Power & Light Company
Docket No. 130001-EI
Staff's 2nd Set of Interrogatories
Question No. 13
Attachment I Page 1 of 1

Scherer
RFPs Issued
in 2012

	Supplier	Tonnage Bid	Coal Quality Btu/lb	% Sulfur	Delivered Price $/mmbtu
Q3 2012 Spot		45,000	8,800	0.35	2.211
		45,000	8,800	0.35	2.211
		45,000	8,800	0.24	2.226
		45,000	8,700	0.22	2.359
		45,000	8,400	0.35	2.545
Q4 2012 Spot		100,000	8,800	0.35	2.198
		20,000	8,400	0.33	2.239
		100,000	8,800	0.35	2.244
		100,000	8,850	0.35	2.292
		30,000	8,800	0.24	2.305
		50,000	8,350	0.38	2.317
		100,000	8,700	0.22	2.346
		100,000	8,350	0.33	2.349
		50,000	8,550	0.25	2.388
		100,000	8,400	0.35	2.500
Dec 2012 Spot		75,000	8,800	0.35	2.313
		75,000	8,700	0.22	2.333
		75,000	8,850	0.35	2.342
		75,000	8,400	0.35	2.400
		75,000	8,350	0.35	2.418
Q1 2013 Spot		100,000	8,800	0.35	2.272
		30,000	8,800	0.24	2.281
		100,000	8,800	0.35	2.287
		100,000	8,800	0.22	2.302
		50,000	8,350	0.38	2.340
		100,000	8,400	0.35	2.389

Q.

For each RFP for coal that JEA issued in 2012 for FPL's interest in St. Johns River Power Park Units 1 and 2 please provide the following information:

a) List the bids received. Include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

b) Describe what action was taken for each RFP. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A.

JEA did not issue any RFPs for coal to supply the St. Johns River Power Park Units 1 and 2 during 2012.

Q.
During 2012, did FPL experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state charges, if any.

A.
There were no transportation constraints at either Plant Scherer or the St. Johns River Power Park in 2012.

FPL was allocated $266,176.40 in detention charges via billings by Norfolk Southern, the railroad serving Plant Scherer, in 2012. Most of the detention expense was attributable to locomotive charges that were assessed for exceeding the four-hour allowance for unloading trains during the first and second quarters.

Ship demurrage charges associated with vessel deliveries of coal to SJRPP, via the St. Johns River Coal Terminal, were booked in April and September of 2012. FPL's allocation was $19,862.94 and $15,763.90, respectively. The April expense was to settle fiscal year 2011 shipments. The September expense was an accrual for fiscal year 2012 shipments.

Q.

Please describe FPL's process for purchasing natural gas including how it solicits and communicates with suppliers and how it negotiates supply contracts.

A.

FPL's natural gas procurement process is based on delivering cost minimization within the framework of supply reliability. FPL's procurement process seeks to diversify FPL's gas supply portfolio by executing transactions with varying durations, utilizing multiple suppliers. Transactions are executed under master agreements that have been entered into with numerous natural gas suppliers. The master agreements contain general contract provisions that apply to individual transactions executed with suppliers. In general, the process FPL employs for purchasing natural gas involves contacting credit worthy suppliers to discuss/negotiate requirements, receipt points, delivery points, pricing, volumes, and any other relevant issues. Transactions that best meet FPL's requirements from a reliability and cost perspective are executed with suppliers. FPL's natural gas procurement is divided into term, monthly and spot procurement. Additional details for each category are provided below:

Term Procurement:

FPL's term procurement generally pertains to the seasonal and yearly volumes of natural gas that FPL procures for the current year and up to two years into the future. Term procurement covers a portion of FPL's baseload requirements and typically carries the highest level of firmness. Projections for total system natural gas requirements are developed utilizing a unit commitment/optimization software application called GenTrader. Target term procurement volumes are determined based on the output data of the GenTrader program. Term procurement volumes typically range from [redacted] of the average projected requirements during the November through March (winter/shoulder) time period and from [redacted] of the average projected requirements during the April through October (summer/peak) time period. Transactions that fall under term procurement are executed using index-based pricing, typically NYMEX plus/minus basis or a point-specific, Inside FERC posting. FPL's natural gas portfolio includes numerous receipt points across many different areas, as well as upstream transportation capacity. An important factor that FPL considers when determining the make-up (both location and volume) of its term procurement portfolio is receipt point liquidity, both historical and projected. Receipt points that have, or are projected to have limited liquidity can be good candidates for term procurement to help ensure the reliability of supply during peak demand months. Other factors considered for term procurement are historical supplier performance, volume availability and pricing. Term procurement is accomplished over a longer period of time which can help reduce volatility and minimize the potential for paying higher premiums on larger volumes. Executing term

procurement over a longer period of time can also help average out the effect of gas market trends (particularly regarding basis spreads) which can help ensure that FPL is paying a fair market price for natural gas. Finally, executing term procurement over a longer period of time allows changes in FPL's generation stack and pipeline infrastructure portfolio to be incorporated into the procurement strategy.

Monthly Procurement:

Monthly procurement is the second stage of the overall natural gas procurement process. Monthly procurement allows FPL to "fine tune" its baseload supply versus the "swing" volume it will potentially experience on a daily basis. Prior to the beginning of each month, the latest GenTrader projections are evaluated with specific focus given to the projected minimum, maximum and average daily requirements output by the program. The gap(s) between the monthly projected requirements (minimum, maximum and average) and the term procurement volume provides the foundation for determining monthly procurement requirements. A major factor in determining how much of this gap to fill with monthly procurement is based on determining an acceptable level of potential "swing" volumes that FPL may need to acquire in the spot market. FPL must find the balance between being oversupplied with term and monthly volumes and having a manageable "swing" position if actual conditions are markedly different than forecasted conditions. FPL considers the same factors (receipt point liquidity, supplier performance, volume availability…etc.) for monthly procurement as it does for term procurement. Additionally, factors such as weather uncertainty, pipeline maintenance, generating unit information, and seasonal receipt point liquidity are taken into account. On average, winter/shoulder months are more susceptible to an oversupply situation and with better receipt point liquidity, FPL can keep a larger "swing" position during this time period. The opposite holds true for summer/peak demand months and therefore, FPL prefers to keep a tighter potential "swing" position during this time period.

Spot Procurement:

Spot procurement includes day-ahead and intra-day transactions. Day-ahead purchases are the third stage of the natural gas procurement process. GenTrader simulations are executed on a day-ahead basis and include all current information regarding weather and unit availability. Day-ahead purchases are executed to fill the gap between the projected next-day requirements and the total volume of gas that was procured between term and monthly purchases. While there are rare situations where FPL may not have to execute day-ahead purchases, for the most part FPL is a consistent participant in the daily (spot) market. Intra-day procurement is the fourth and final stage of the natural gas procurement process. Intra-day transactions allow FPL to match its natural gas supply as close as possible to its requirements. In general, spot procurement is executed to accomplish the most efficient

utilization of FPL's remaining gas transportation capacity and deliver the lowest cost supply. FPL can also utilize pipeline imbalance capability and natural gas storage to further balance its supply and demand.

Q.

For each natural gas supply contract that FPL executed in 2012, describe the process that led to the contract, and list the supplier, volume requirements, delivered price information, as well as the primary pipeline over which the gas is delivered.

A.

The attached spreadsheet contains all of the requested data for each natural gas transaction that FPL executed during 2012. The natural gas price information shown in the attached table reflects receipt point pricing. The processes that led to the execution of these transactions are described in FPL's response to Interrogatory No. 16.

Florida Power & Light Company
Docket No. 130001-EI
Staff's 2nd Set of Interrogatories
Question No. 17
Attachment I

ATTACHMENT – REDACTED

2012 Natural Gas Transactions

Q.
In 2012, did FPL participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response.

A.

Yes, in the normal course of business, FPL participated in capacity discussions with pipeline companies during 2012. FPL also participated in several open seasons and entered into the following transactions to secure upstream pipeline capacity:

1) Executed a released-capacity transaction for 145,000 MMBtu/day with Gulf South Pipeline Company LP (Gulf South) for firm pipeline capacity for the summer periods (May – October) beginning 4/1/2013 thru 10/31/2017.

2) Participated in an Open Season with Gulf South and ultimately contracted for 100,000 MMBtu/day for ten years. The project is an expansion of their existing system and is projected to be placed into service on 4/1/2015.

Q.

Please describe FPL's process for purchasing heavy oil and light oil including how it solicits and communicates with suppliers and how it negotiates supply contracts. As part of this response, describe how FPL's shift away from heavy oil generation affects its fuel oil buying process.

A.

FPL has executed master agreements with various potential fuel oil counterparties that could supply either heavy fuel oil or light fuel oil. These agreements contain general contract provisions that would apply to the individual transactions executed with a supplier. When FPL has a heavy fuel oil or light fuel oil procurement need, personnel contact the various suppliers who have acceptable credit, generally by telephone, to discuss requirements, delivery windows, delivery methods, costs, and any other pertinent transaction issues. Transactions are executed with the counterparty that best meets FPL's requirements, including cost.

FPL's shift away from heavy oil generation has resulted in a reduced need to procure heavy fuel oil. As summarized in the response to Staff's Second Set of Interrogatories, No. 20, there were a limited number of heavy fuel oil purchases during 2012.

Q.
For each heavy oil supply contract that FPL executed in 2012, describe the process that led to this contract and include the supplier, volume, and delivered price information, as well as the primary delivery method.

A.
The heavy fuel oil deals executed during 2012, along with the transaction date, supplier name, volume, pricing, and primary delivery method are summarized in the attached file. The process that led to the execution of each transaction is described in the response to Staff's 2nd Set of Interrogatories, No. 19.

Florida Power & Light Company
Docket No. 130001-EI
Staff's 2nd Set of Interrogatories
Question No. 20
Attachment I Page 1 of 1

2012 Heavy Oil Purchases

Date	Supplier	Sulphur Grade	Volume (Bbls)	Delivery Method	Price Delivered ($/Bbl)
7/9/12	Freepoint Commodities LLC	0.40%	104,165	Barge	[redacted]
8/1/12	Freepoint Commodities LLC	0.30%	57,647	Barge	
12/14/12	Freepoint Commodities LLC	0.70%	100,861	Barge	

Q.

For each light oil supply contract that FPL executed in 2012, describe the process that led to this contract and include the supplier, volume, and delivered price information, as well as the primary delivery method.

A.

The light fuel oil deals executed during 2012, along with the transaction date, supplier name, volume, pricing, and primary delivery method are summarized in the attached file. The process that led to the execution of each transaction is described in the response to Staff's 2nd Set of Interrogatories No. 19.

Florida Power & Light Company
Docket No. 130001-EI
Staff's 2nd Set of Interrogatories
Question No. 21
Attachment I Page 1 of 1

2012 Light Oil Procurement

Date	Supplier	Volume (Gallons)	Delivery Price ($/Gallon)	Delivery Method
1/31/12	APEC	756,000	[redacted]	Tank Truck
1/27/12	APEC	38,010		Tank Truck
3/30/12	APEC	247,926		Tank Truck
4/30/12	APEC	389,886		Tank Truck
5/16/12	TransMontaigne	873,134		Pipeline
5/31/12	APEC	706,524		Tank Truck
6/30/12	APEC	238,434		Tank Truck
10/31/12	APEC	1,665,300		Tank Truck
11/30/12	APEC	461,244		Tank Truck
11/30/12	APEC	282,702		Tank Truck
12/26/12	Port Consolidated	220,332		Tank Truck
12/31/12	Freepoint Commodities LLC	255,864		Tank Truck
12/31/12	Freepoint Commodities LLC	296,940		Tank Truck
12/31/12	Freepoint Commodities LLC	153,048		Tank Truck

Q.

Please describe FPL's process for purchasing power on a long-term contractual basis including how it solicits and communicates with suppliers and how it negotiates supply contracts and transmission arrangements.

A.

FPL routinely communicates with wholesale power suppliers in and around the Florida market to determine if there are any opportunities to purchase capacity and energy to meet the needs of FPL's customers. As an example, due to various generation maintenance outages in 2012, it was determined that additional capacity was necessary to maintain adequate reliability. As a result, FPL worked with 5 different suppliers to negotiate 4 long-term wholesale power supply contracts for capacity and energy. The negotiations for these contracts varied from extending terms and conditions of an existing deal at new prices, to negotiating a new agreement. Once the terms and conditions were agreed to by both FPL and the supplier, transmission requests were made by FPL to ensure the capacity and energy could be delivered to meet FPL customer needs.

Q.
For each purchased power supply contract that FPL executed in 2012, describe the process that led to this contract and include the supplier, volume, and delivered price information, as well as the transmission arrangements.

A. In each case, the prospective supplier was approached about their desire to sell capacity and energy to FPL. The prospective suppliers were asked to provide term sheets with basic terms and conditions including pricing and structure. Based on the economics of the proposed term sheets, further discussions were initiated with the prospective suppliers in an attempt to negotiate the best terms and conditions for FPL. Once FPL and the prospective supplier came to agreement on a proposed contract for wholesale power supply, various internal approvals of the contract were requested (and granted), in accordance with the FPL Risk Management Policies and Procedures.

In each case, FPL requested and was granted firm network transmission service from FPL Transmission in accordance with the FPL Transmission Tariff. For TECO, an additional transmission request was required for firm point to point transmission service from TECO Transmission to FPL Transmission.

The supplier, volume, and delivered price information, as well as the transmission arrangements for each case described are reflected in Attachment I to this answer.

Florida Power & Light Company
Docket No. 130001-EI
Staff's 2nd Set of Interrogatories
Question No. 23
Attachment Page 1 of 1

Supplier	Volume (MW)	Term	[redacted]
DeSoto	305	Jan-Dec	
TECO	25-125	Jan-Dec	
Seminole	150	Apr-Sep	
Oleander	155	Jun-Sep	

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 5th day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 13 through 23 from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 13-23) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5th day of March, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

56

FPL's Responses to Staff's Third Set of Interrogatories (Nos. 24-34)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 56
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0130-0149]

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please state whether performance improvement in availability and heat rate also increases FPL's ability or opportunity to make off-system economy sales. As part of the response, please provide the MWh and dollar amounts of off-system economy sales by year for 2006 through 2012.

A.

FPL's ability to participate in the power market is primarily driven by its marginal cost position relative to other utility systems. From a high-level perspective, performance improvements in availability and heat rate should increase FPL's ability to make off-system economy sales as these improvements drive lower marginal costs and therefore, improve FPL's competitive position in the power market. However, there are many other factors which also impact FPL's marginal costs and its competitive position in the power sales market. The relationship between fuel prices, FPL's system load versus the load on other utility systems, generation availability (by unit/fuel type) and planned maintenance are all important factors that impact FPL's marginal costs at any given point in time. For example, a day with higher system loads coupled with planned maintenance on a baseload combined cycle unit may result in FPL having higher marginal costs relative to the power market, putting FPL at a competitive disadvantage for power sales, but allowing for economic power purchases. Therefore, while availability and heat rate improvements can help FPL's overall competitive position, these two factors, considered in isolation on a real-time basis, will not accurately determine FPL's ability to participate in the power sales market. Finally, separate from a cost perspective, transmission service must be available for FPL to make economy sales.

Off-system economy sales information by year for the period from 2006 through 2012:

Economy Sales

Year	MWh	Total Revenue
2012	369,827	$12,008,526
2011	468,676	$19,439,082
2010	432,298	$21,229,555
2009	933,050	$40,392,586
2008	1,165,517	$75,840,504
2007	1,440,431	$89,979,992
2006	1,730,968	$103,843,807

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please state whether performance degradation in availability and heat rate also increases FPL's ability or opportunity to make off-system economy purchases. As part of the response, please provide the MWh and dollar amounts of off-system economy purchases by year for 2006 through 2012.

A.

FPL's ability to participate in the power market is primarily driven by its marginal cost position relative to other utility systems. From a high-level perspective, performance degradation in availability and heat rate should increase FPL's opportunity to make off-system economy purchases as these factors drive higher marginal costs and therefore, increase the likelihood that FPL could purchase power at a lower cost than its own generation. There are many other factors, however, that also impact FPL's marginal costs and its position relative to the power market. The relationship between fuel prices, FPL's system load versus the load on other utility systems, generation availability (by unit/fuel type) and planned maintenance are all equally important factors that impact FPL's marginal costs at any given point in time. Changing the weather assumptions in the example given in Interrogatory No. 24 demonstrates the importance of other factors on FPL's relative position in the power market. For example, mild temperatures in Florida, coupled with cold temperatures in Georgia, could mitigate the impact that FPL's higher marginal costs have on its relative position in the power market. FPL could move from a buyer to a seller in this scenario as the marginal costs for other utilities move higher, due to increased load in their territories resulting from cold temperatures. While FPL's marginal costs are higher due to the planned maintenance, the weather impact may put FPL at a competitive advantage in the power sales market. Therefore, while availability and heat rate degradation can lead to an increase in economy purchases, these two factors, taken in isolation on a real-time basis, will not accurately determine FPL's ability to participate in the power purchases market. Finally, separate from a cost perspective, transmission service must be available for FPL to make economy purchases.

Off-system economy purchases information by year for the period from 2006 through 2012:

Economy Purchases

Year	MWh	Transaction Cost
2012	813,947	$33,916,745
2011	1,314,648	$80,531,513
2010	2,212,468	$140,355,049
2009	1,058,376	$54,486,449
2008	649,823	$54,782,807
2007	1,121,569	$69,090,195
2006	1,699,423	$99,017,296

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the data in the following table.

A.

Year	GPIF Total Points	GPIF Reward/ Penalty $000	System Fuel Cost at Target Level of Performance $000	System Fuel Cost at Actual Level of Performance $000	Fuel Savings / Costs $000
2006	3.12	8,903	5,745,498	5,695,688	49,810
2007	1.83	5,339	5,541,861	5,511,341	30,520
2008	3.75	11,525	5,212,452	5,156,245	56,207
2009	2.66	8,791	5,586,188	5,530,635	55,553
2010	1.81	6,571	3,407,298	3,388,913	18,385
2011	1.92	7,704	2,937,874	2,918,114	19,760
2012	4.75	22,045	3,023,585	2,974,542	49,043

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the data in the following table.

A.

Year	EAF Total Points	EAF Reward / Penalty $000	System Fuel Cost at Target Level of EAF Performance $000	System Fuel Cost at Actual Level of EAF Performance $000	Fuel Savings / Costs due to EAF $000
2006	3.46	9,861	5,745,498	5,690,327	55,171
2007	2.63	7,654	5,541,861	5,498,112	43,749
2008	3.96	12,177	5,212,452	5,153,068	59,384
2009	2.28	7,548	5,586,188	5,538,491	47,697
2010	2.46	8,965	3,407,298	3,382,212	25,086
2011	1.90	7,654	2,937,874	2,918,244	19,630
2012	4.19	19,453	3,023,585	2,985,384	38,201

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the Equivalent Forced Outage Rate (EFOR) data for each GPIF unit by year for 2006 through 2012.

A.

GPIF UNIT	2006	2007	2008	2009	2010	2011	2012
Ft. Myers 2	2.74	1.37	1.48	0.52	0.81	3.41	0.34
Lauderdale 4	0.93	1.21	3.66				
Lauderdale 5	0.50	0.97	1.79	0.89			
Manatee 1		0.00					
Martin 1	0.21	13.82					
Martin 2	0.49		0.13				
Martin 3	0.84		0.65				
Martin 4	0.57	1.31	0.67	0.84			
Martin 8				2.79	1.41	0.80	1.65
Manatee 3				0.28	1.03	4.76	0.05
Sanford 4		0.61	0.82	4.23	0.55	0.43	0.33
Sanford 5	11.43	1.23	0.77	0.42	0.39	0.47	
Scherer 4	0.10	2.39	0.27	2.73	0.55	1.46	1.14
St. Lucie 1	0.14	0.68	2.07	0.33	9.21	4.24	2.10
St. Lucie 2	3.27	8.29	5.20	13.94	2.24	10.50	2.16
Turkey Point 3	2.02	7.97	2.16	6.29	3.24	2.38	0.84
Turkey Point 4	3.72	0.15	2.96	0.27	4.49	3.33	0.00
Turkey Point 5						0.38	0.09

Note: Shaded cells reflect years when the units were not selected as GPIF units

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please describe the method of estimating the maximum fuel savings reported in FPL's GPIF projection and actual filings. As part of the response, please identify the source and reasoning for the use of the production simulation model for the actual filings.

A.

At the onset of the process, the PMArea production simulation model is used to estimate the total fuel cost of the FPL system for the GPIF projection period. Once the availability and heat rate targets and the corresponding range of improvement for each GPIF unit are developed, the PMArea model is used again to determine the fuel cost differential between the unit performing at its target and its maximum range of improvement. This cost differential is expressed in terms of energy replacement costs and represents the maximum fuel savings the unit could contribute should it achieve its maximum range of improvement from its target. The simulation is done individually for each GPIF unit availability performance and for each nuclear unit heat rate performance. The fossil units' heat rate maximum fuel savings is calculated by the ratio of the range of improvement of a unit to its target heat rate applied to the production costs of the unit estimated by the PMArea model. Once this is completed, the estimated individual unit fuel savings for each metric is added to determine the cumulative maximum fuel savings reported on FPL's GPIF projection filings.

At the end of the projection period and in preparation for the actual filing, the estimated maximum fuel savings calculated for the projection period are used to develop the Generating Performance Incentive Table for each GPIF unit. This Table shows the estimated fuel savings contribution at various levels of performance from each GPIF unit for availability and heat rate performance. The estimated maximum fuel savings from the PMArea model for the GPIF projection period are used for the actual filings for consistency reasons and to maintain the same basis for fuel costs between the projection and the actual filing so that the fuel savings calculated are a result of unit performance and not the result of changes in fuel prices.

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide a comparison of the projected and actual monthly fuel cost for 2012 and factors contributing to the difference. As part of the response, please provide the data and calculations supporting the following:

a) Difference in average monthly heat rates for the aggregated GPIF units.
b) Difference in average monthly heat rates for the system (including non-GPIF units).
c) Difference in average monthly fuel price ($/mmBtu) for the aggregated GPIF units.
d) Difference in average monthly fuel price ($/mmBtu) for the system (including non-GPIF units).
e) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors outside FPL's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model.
f) Difference in monthly fuel cost dollars for the system (including non-GPIF units), caused by factors outside FPL's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model.
g) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors within FPL's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by FPL, and demonstrate whether the difference can be calculated and verified without the use of production simulation model.
h) Difference in monthly fuel cost dollars for system (including non-GPIF units), caused by factors within FPL's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by FPL, and demonstrate whether the difference can be calculated and verified without the use of production simulation model.

A. 30a

Heat Rate (Btu/kWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Projection	8,615	8,311	7,895	8,466	8,347	8,497	8,450	8,466	8,518	8,606	8,752	8,706
Actual	8,832	8,771	8,272	8,412	8,568	8,708	8,670	8,361	8,402	8,539	8,540	8,643
Difference*	217	461	377	(53)	221	211	220	(105)	(117)	(67)	(212)	(63)

*Differences may not add-up due to rounding

30b

HEAT RATE Btu/Kwh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Projection	7,996	7,719	7,561	8,091	7,919	8,023	7,961	8,090	8,127	8,140	7,904	8,072
Actual	8,224	8,167	7,970	8,219	8,309	8,390	8,371	8,282	8,201	8,206	8,186	8,249
Difference *	228	448	409	128	390	367	411	192	74	66	282	178

* Differences may not add up due to rounding

30c

Fuel Price ($/mmBtu)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Projection	3.10	3.51	3.81	3.42	3.30	3.19	3.19	3.19	3.17	3.17	3.01	3.11
Actual	2.90	2.90	3.19	3.14	2.97	2.87	3.05	3.26	3.16	3.05	3.20	2.94
Difference*	(0.20)	(0.61)	(0.63)	(0.28)	(0.34)	(0.32)	(0.15)	0.06	(0.01)	(0.12)	0.19	(0.18)

*Differences may not add-up due to rounding

30d

Fuel Price ($/mmBtu)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Projection	4.10	4.37	4.51	4.14	4.11	4.04	4.11	4.43	3.99	3.89	4.01	3.86
Actual	3.76	3.69	3.87	3.87	3.74	3.87	4.03	4.18	3.96	3.99	4.12	3.89
Difference*	(0.34)	(0.68)	(0.64)	(0.27)	(0.37)	(0.17)	(0.08)	(0.25)	(0.03)	0.09	0.12	0.03

* Difference may not add-up due to rounding

30e.

FPL does not have the necessary information to provide the requested data and calculations. The projection of monthly fuel costs of all FPL units, including the aggregated GPIF units, is based on the output of a production simulation model. Differences in fuel costs are based on factors which are often outside of FPL's control. These factors are: disparities between actual and projected load, fuel prices, unit performance and outage, economy purchases and sales, and others.

The impact of any one of these factors may be calculated, with reasonable accuracy, without the use of a production simulation model. For example, an unplanned nuclear outage would cause an increase in the operation of some of the FPL units. In order to estimate what impact such an outage would have, an assumption as to which units would replace this energy would have to be made to calculate the fuel cost impact. The result of this calculation would provide the fuel cost difference due to this individual factor (i.e., a nuclear unit outage). Such an estimate might yield reasonably accurate results if there were only one factor that changed from the original projections. However, when a difference is caused by several factors acting simultaneously it becomes very difficult to compute the overall effect. The effects of several individual factors, operating on the system at the same time, are usually closely related; the overall effect is different than the sum of the individual effects.

30f.

FPL does not have the necessary information to provide the requested data and calculations. Please refer to the response to interrogatory 30e.

30g&h

With one limited exception, FPL does not have the necessary information to provide the requested data and calculations. As to interrogatory 30g, FPL's GPIF filings provide a reasonable and appropriate measure of the difference in fuel costs for the GPIF units due to factors within FPL's operational control. FPL does not, however, perform comparable calculations of the impact of operational factors with respect to the non-GPIF units, which are included in interrogatory 30h.

As to both interrogatories 30g and 30h, FPL does not believe that it would be meaningful to calculate the monthly fuel-cost impact of resource planning decisions, for either GPIF or non-GPIF units. In order to determine the fuel-cost impact of resource planning decisions, one would have to assume a "change case" in which FPL's resource planning decisions were different than what FPL actually pursued. There would be no clearly correct answer as to what this change case would be, but whatever assumptions were made about the "change case" would be the controlling factor in the calculated fuel-cost impact of FPL's resource planning decisions.

FPL's Power Generation Business Unit (PGD) and the Nuclear Business Unit operate and maintain their generating fleet in a manner which is consistent with the purpose of the GPIF. As such, FPL seeks to maximize fuel efficiency, availability and reliability of its fleet to the extent possible given FPL's system constraints. For example, PGD tries to prevent equipment failures that may cause a significant difference in system fuel cost by utilizing the Fleet Performance and Diagnostic Center ("FPDC"). Here, critical fossil fleet operating parameters are monitored "24/7" online using advanced statistical techniques. Automated statistical applications detect change in performance and alert employees. FPL can also analyze the equipment's ability to perform according to its rated specifications and evaluate ways to improve efficiencies. The goal is to identify equipment degradation far enough in advance of a failure so corrective measures can be put in place. These initiatives and efforts are focused on preventing or mitigating failures and optimizing efficiency and are shared across the entire fossil fleet. In addition, PGD applies a centralized fossil fleet maintenance concept which adds efficiency to the process by planning and allocating resources at a fleet-wide level, instead of having each site determine its requirements independently. The team then uses Lean Six Sigma concepts during overhaul planning and execution to optimize the outage duration, with input from the fleet equipment experts, who also provide engineering support from a centralized location. This "Fleet Team" approach organizes its technical support groups around major plant components such as boilers, steam turbines, combustion turbines and generators. The Fleet Teams contain experienced subject matter experts who provide technical recommendations during an outage and, based on the condition of the equipment, determine if the equipment can operate safely and reliably until a future maintenance interval. Programs to assess and monitor the condition of the equipment allow the team to lower costs by safely extending the maintenance requirements to a future date, using data to support the recommendation.

As explained in the response to interrogatory 30e, calculating the fuel costs difference caused by several factors acting simultaneously on the FPL system becomes difficult to compute without the use of a production simulation.

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please state the manner in which the GPIF mechanism may be modified to achieve the same fuel savings and efficiency objective that will allow fuel savings to be calculated and verified without the use of production simulation model.

A.

The PMArea production simulation model is an integral part of FPL's GPIF mechanism. To start, it is utilized to estimate the net generation used in determining the generating units to be included in the GPIF calculation. In addition, it is used to estimate net output factors and production costs (as explained in answer to Question 29 of this interrogatory) used in the GPIF calculations. As such, FPL cannot identify at this time a way in which the GPIF mechanism could be modified so that it did not require the use of the PMArea production simulation model.

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Describe the manner in which FPL sets performance expectations for individual unit production efficiency, measures performance against expectations, and calibrates incentives for management accountability for the individual plant.

A.

Individual unit production efficiency performance expectations are set, measured and calibrated in a manner consistent with the description provided in answer to Interrogatory 33.

Nuclear Plants

FPL utilizes the following operating indicators for the St. Lucie and Turkey Point nuclear units to measure performance:

- INPO Index - The INPO index is a metric of nuclear plant safety and reliability widely used in the U.S. nuclear power industry.
- Net Generation
- Equipment Reliability Index (ERI)
- Refueling outage performance
- Forced Loss Rate (FLR)
- Safety (OSHA Recordable Injuries)
- Cost per MWh generated
- Human Performance Index

Each site has an annual operating plan and results on each metric are compiled and used to assess overall management performance.

Fossil Plants

For fossil plants, FPL utilizes the following main operating indicators to measure production efficiency:

- Net Generation
- Net Heat Rate
- Equivalent Availability Factor (EAF)
- Equivalent Forced Outage Rate (EFOR)
- Safety (OSHA Recordable Injuries)
- Operations and Maintenance (O&M) costs
- Capital expenditures

Management accountability for individual plants is aligned and consistent with the overall performance goal expectations set for the company. Achieving these goals ensures that the plant, the business unit and the company accomplishes its expected results.

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Describe the manner in which FPL sets performance expectations for total system production efficiency, measures performance against expectations, and calibrates incentives for management accountability for the total system.

A.

FPL has a strong pay for performance philosophy. The fundamental objective of the company's incentive program is to motivate and reward actions that will increase long-term value. The program is designed to retain, motivate, attract, reward and develop high-quality, high-performing leadership whose talent and expertise help the company achieve performance expectations measured by a variety of financial and operational metrics. The company selects a balanced and broad mix of performance metrics in order to ensure against over-focus on any one aspect of the business that might lead to compromising long-term value creation.

At year's end, the company assesses whether the operational performance goals have been achieved, exceeded or missed, the degree of difficulty of achieving each, and the company's performance with respect to each goal and arrives at an aggregate determination for the company performance as compared to its goals. Then, the company exercises its business judgment and discretion and whenever practical assigns incentives for management accordingly. That is, performance that is above the set goals will generally lead to incentive for management that is above the targeted amounts; conversely, performance below the set goals, will lead to incentive for management below the targeted amounts.

Regarding production efficiency, the company calibrates management incentives by routinely assessing management performance against strategic performance objectives set at levels that represent excellent performance and superior to the results of typical companies in FPL's industry. These results are routinely evaluated based on internal reviews of publicly-available information and information provided by consultants and industry associations to ensure the company's goals stay relevant and are accordingly adjusted periodically based on the dynamics of the industry in which FPL operates.

Q.

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Describe the manner in which FPL evaluates the effectiveness of its incentive mechanism, makes improvement in the mechanism, and promotes sharing best practices that improve production efficiency.

A.

FPL evaluates the effectiveness of its incentive mechanism and makes improvements in a manner consistent with the description provided in answer to Question 33 of this interrogatory. Regarding the promotion of sharing best practices that improve production efficiency, FPL utilizes its Nuclear Excellence Model ("NEM"), which is the foundation of its commitment to achieve and sustain excellence in all aspects of its nuclear operations. The strategic focus areas of the NEM are: (1) Operational Excellence; (2) Organizational Effectiveness; (3) Generation Reliability; and (4) Effective Business and Financial Performance. For example, a Daily Fleet Message is published that includes a section titled "Learning from Operating Experience" which describes an industry event that FPL utilizes as a tool to learn from previous experience and apply to daily operations.

FPL and its affiliates collectively comprise the third largest nuclear fleet operator in the United States, owning and operating eight nuclear units at five locations. There are important benefits and synergies to FPL and its customers from the affiliation with a larger nuclear fleet. FPL is able to use operational experience from its affiliate plants and incorporate lessons learned to the FPL nuclear fleet. By doing so, FPL has made improvements that have increased equipment reliability which prevent events from occurring, resulting in improved nuclear safety and plant reliability. FPL also receives operational experience in occupational health and safety matters that improve plant industrial and radiological safety. FPL continuously pursues standardization of programs and procedures, where applicable, and both shares and receives data on best practices to the benefit of FPL's nuclear fleet, improving nuclear safety, efficiencies, and reducing costs.

FPL's Power Generation Business Unit applies a centralized fossil fleet maintenance concept which adds efficiency to the process by planning and allocating resources at a fleet-wide level, instead of having each site determine its requirements independently. The team then uses Lean Six Sigma concepts during overhaul planning and execution to optimize the outage duration, with input from the fleet equipment experts, who also provide engineering support from a centralized location. This "Fleet Team" approach organizes its technical support groups around major plant components such as boilers, steam turbines, combustion turbines and generators. The Fleet Teams contain experienced subject matter experts who provide technical recommendations during an outage and, based on the condition of the equipment, determine if the equipment can operate

safely and reliably until a future maintenance interval. Programs to assess and monitor the condition of the equipment allow the team to lower costs by safely extending the maintenance requirements to a future date, using data to support the recommendation. This Fleet Team concept allows FPL to share best practices to improve production efficiency throughout the fossil fleet.

Another mechanism FPL utilizes to promote sharing best practices is the Fleet Performance and Diagnostic Center ("FPDC"). Here, critical fossil fleet operating parameters are monitored "24/7" online using advanced statistical techniques. Automated statistical applications detect change in performance and alert employees. FPL can also analyze the equipment's ability to perform according to its rated specifications and evaluate ways to improve efficiencies. The goal is to identify equipment degradation far enough in advance of a failure so corrective measures can be put in place. These initiatives and efforts are focused on preventing or mitigating failures and optimizing efficiency and is shared across the entire fossil fleet. In fact, due to its success in improving production efficiency, FPL recently announced the creation of a cross-functional effort aimed at sharing best practices between the fossil and nuclear business units in order to leverage the FPDC's capabilities and technical expertise.

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 19th day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 24 and 25 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 24-34) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of March, 2013.

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida, at Large

My Commission Expires:
May 30, 2013

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 18th day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Carine Bullock, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 26 through 28, 30a-d, and she cosponsored interrogatory numbers 29, 30g&h and 31 through 34 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 24-34) in Docket No(s). 130001-EI, and that the responses are true and correct based on her personal knowledge.

Carine Bullock

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of March, 2013.

JAYNE LORING DAVIS
MY COMMISSION # DD908031
EXPIRES September 14, 2013
(407) 398-0153 FloridaNotaryService.com

Notary Public
State of Florida, at Large

My Commission Expires:
9-14-13

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 21st day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Daisy Iglesias, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 30 e&f and she co-sponsored the answers to interrogatory numbers 30 g&h from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 24-34) in Docket No. 130001-EI, and that the responses are true and correct based on her personal knowledge.

Daisy Iglesias

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of March, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lily A Rodriguez
My Commission EE 875812
Expires 02/17/2017

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 21st day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Pamela Metz, who is personally known to me, and she acknowledged before me that she co-sponsored interrogatory numbers 32 through 34 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 24-34) in Docket No(s). 130001-EI, and that the responses are true and correct based on her personal knowledge.

Pamela L Metz
Pamela Metz

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of March, 2013.

Jo Retha Forbes
Notary Public
State of Florida, at Large

My Commission Expires:

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 8, 2014
Commission # DD 948300

57

FPL's Responses to Staff's Fourth Set of Interrogatories (Nos. 35-38)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 57
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0150-0158]

Q.

Please refer to page 13 of the March 1, 2013 testimony of FPL witness Terry Keith, lines 19 through 22. Also refer to appendix II, page 3, of this testimony. How does the security fence installed at the Port Everglades terminal qualify as an incremental security cost according to Order Nos. PSC-02-1761-FOF-EI and PSC-03-1461-FOF-EI?

A.

Post-9/11, the MTSA (Maritime Transport Security Act) determined that the Port Everglades plant is an MTSA location, meaning that its security must comply with MTSA requirements. Under guidelines set forth by the MTSA, FPL was required to put in a 10 foot reinforced fence surrounding the plant site. The fencing design was provided as a standard for MTSA fencing by the U.S. Army Corps of Engineers and requires a concrete base of 3000 psi concrete and three levels of double stranded barbed wire, with all materials consisting of galvanized steel. This project included 300 feet of fencing along the South side of the Port Everglades Property at an estimated cost of $50,000.

Q.

Please refer to page 10 of the March 1, 2013 testimony of FPL witness Terry Keith, lines 9 through 18. To what extent does FPL intend to continue to follow Order No. PSC-00-1744-PAA-EI regarding the incentive mechanism? Please explain.

A.

As discussed on page 10 of the March 1, 2013 testimony of FPL witness Terry Keith, lines 9 through 18, FPL will not be calculating a shareholder incentive related to wholesale power sales, as discussed and ordered in Commission Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI, beginning in 2013. Instead, as ordered by the Commission in Order No. PSC-13-0023-S-EI, in Docket No. 120015-EI, FPL will implement an incentive mechanism that includes the sharing of gains resulting from electric wholesale purchases, wholesale sales, and asset optimization.

Q.

Please refer to page 14 of FPL witness Terry Keith's March 1 testimony, lines 15 through 18. Please define and explain Capacity Availability Performance Adjustment (CAPA) payments. As part of this explanation, please include a complete copy of the documents (contract pages, etc.) that set the terms for these payments.

A.

Capacity Availability Performance Adjustment (CAPA) payments are contractual components of the monthly capacity payments made to Southern Company Services, Inc. for power purchased from the Franklin, Harris, and Scherer units, and approved by the Commission in Order No. PSC-04-1276-FOF-EI, in Docket No. 040001-EI. [redacted]

The detailed CAPA payment calculations are set forth in Appendix A of each contract. Appendix A for the Franklin, Harris and Scherer purchased power contracts are included as an attachment to this response.

Florida Power & Light Company
Docket No. 130001-EI
Staff's 4th Set of Interrogatories
Question No. 37
Attachment
Page 1 of 1

FPL's Response to Staff's Fourth Set of Interrogatories No. 37 is confidential in its entirety.

Q.

In its 2013 actual/estimated or 2014 projected testimony, will FPL propose any new contract, new capital project, or other new cost for fuel or capacity cost recovery? If so, please list all such proposals.

A.

Yes. FPL will request recovery of incremental capital costs associated with new NRC requirements imposed on FPL resulting from the events that occurred at the Fukushima Daiichi nuclear power station in March 2011.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 25th day of April, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 35 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 35-38) in Docket No. 130001-EI, and that the response is true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25th day of April, 2013.

JESSICA BRADEN
NOTARY PUBLIC
STATE OF FLORIDA
Comm# DD968567
Expires 3/7/2014

Notary Public
State of Florida, at Large

My Commission Expires:
3/7/14

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 25th day of April, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 36 and 37 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 35-38) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25th day of April, 2013.

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002668
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida, at Large

My Commission Expires:
May 30, 2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 26th day of April, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Mitchell Goldstein, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 38 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 35-38) in Docket No. 130001-EI, and that the response is true and correct based on her personal knowledge.

Mitchell Goldstein

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of April, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 8, 2014
Commission # DD 948300

58

FPL's Responses to Staff's Fifth Set of Interrogatories (Nos. 39-42)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 58
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0159-0165]

Q.

Interrogatory Nos. 39-40 are in regard to the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the actual filings for each year during the period from 2006 through 2012.

A.

	Reward/(Penalty) at Maximum Performance Level $000	Fuel Savings /(Loss) at Maximum Performance Level $000
2006	28,513	159,527
2007	29,138	166,558
2008	30,772	150,073
2009	33,048	208,765
2010	36,389	101,796
2011	40,185	103,074
2012	46,380	91,083

Q.

Interrogatory Nos. 39-40 are in regard to the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the projection filings for each year during the period from 2006 through 2012. If the amounts are different from the ones contained in the actual filings, please explain.

A.

The fuel savings/loss at maximum performance level are the same amounts in the actual and projection filing since they are based on the same production simulation case. However, the reward/penalty at maximum performance level are different between the actual and projection filing amounts since they are based on projected common equity balances for the projection filing and on actual common equity balances for the actual filing.

	Reward/(Penalty) at Maximum Performance Level $000	Fuel Savings /(Loss) at Maximum Performance Level $000
2006	27,367	159,527
2007	27,514	166,558
2008	29,718	150,073
2009	34,351	208,765
2010	35,485	101,796
2011	39,609	103,074
2012	44,213	91,083

Q.

For the following two questions, please refer to the reward (penalty) table (JCB-1 at page 2) in FPL's actual filing for 2012. (Dollars in thousands)

Based on the same interpolation for the $22,045 reward, should the fuel savings at the actual performance level be $43,264, instead of the $49,043 as FPL reported?

A.

Please refer to FPL's filing dated May 13, 2013 for the revised reward and fuel savings. Based on the revised filing, the reward is $20,680 instead of $22,045 and the fuel savings are $46,363 instead of $49,043. Hence, based on the interpolation for the $20,680 reward, mathematically the fuel savings would be $40,612.

Q.

For the following two questions, please refer to the reward (penalty) table (JCB-1 at page 2) in FPL's actual filing for 2012. (Dollars in thousands)

If fuel savings at the actual performance level were $43,264, should the reward be capped at the 50 percent of $43,264, which would be $21,632? If not, please explain.

A.

Please refer to FPL's filing dated May 13, 2013 for the revised reward and fuel savings. As stated in the prior response, mathematically the fuel savings would be $40,612 and the 50 percent reward cap would be $20,306. However, this would only be true if the actual heat rate performance of St. Lucie 1, St. Lucie 2 and Turkey Point 3 in 2012 is ignored. As explained in the testimony of J. Carine Bullock filed on May 13, 2013, due to the effect of the Extended Power Uprates, FPL made adjustments to the actual heat rate and net output factor of these nuclear units for the sole purpose of calculating heat rates that fell within the heat rate regression equation parameters and thus to calculate the reward from these units. These mathematical adjustments were appropriate for the limited purpose of reducing the calculated reward by $2.9 million but they do not affect the actual fuel savings achieved by these units. Consequently, FPL does not believe the fuel savings should be reduced from the actual amount of $46,363.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 28th day of May, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared J. Carine Bullock, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 39-42 from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 39-42) in Docket No. 130001-EI, and that the responses are true and correct based on her personal knowledge.

J. Carine Bullock

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of May, 2013.

JAYNE LORING DAVIS
MY COMMISSION # DD908031
EXPIRES September 14, 2013
(407) 398-0153 FloridaNotaryService.com

Jayne Loring Davis
Notary Public
State of Florida, at Large

My Commission Expires:
9-14-13

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 28th day of May, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared J. Carine Bullock, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 39-42 from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 39-42) in Docket No. 130001-EI, and that the responses are true and correct based on her personal knowledge.

J. Carine Bullock

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of May, 2013.

JAYNE LORING DAVIS
MY COMMISSION # DD908031
EXPIRES September 14, 2013
(407) 398-0153 FloridaNotaryService.com

Jayne Loring Davis
Notary Public
State of Florida, at Large

My Commission Expires:
9-14-13

59

FPL's Responses to Staff's Sixth Set of Interrogatories (Nos. 43-50)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 59
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0166-0175]

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50

Describe the manner in which FPL applied the formulaic representation at Original Sheet No. 3.400 where a provision limits the maximum allowed incentive dollars. As part of the response, please describe whether FPL's application of this provision, if any, has been changed by Commission orders since the inception of the GPIF, including the stipulation by Order No. 18136 in Docket No. 870001-EI.

A.

FPL has consistently applied the formulaic representation at Original Sheet No. 3.400 to calculate the maximum allowed incentive dollars. FPL is not aware of any orders that have changed this provision since the inception of the GPIF. However, it is worth noting that at the time the GPIF program was adopted, fuel cost recovery and GPIF filings were done semi-annually with each filing covering a six-month period. Hence, the maximum allowed incentive dollar formula in Original Sheet 3.400 was based on semi-annual filings. The original calculation required seven months of common equity balances (beginning of period balance plus six months end-of-month balances) and an annual 25 basis points times a 0.5 factor which corresponded to a half-year recovery filing period. Because filings are now done on a yearly basis with each filing covering a 12-month period, FPL utilizes thirteen months of common equity balances (beginning of period balance plus 12 end-of-month balances) and an annual 25 basis points which corresponds to a full 12-month recovery filing period.

The GPIF stipulation in Order No. 18136 in Docket No. 870001-EI does not change the formulaic representation on Original Sheet No. 3.400 but rather it supplements this provision by adding an additional cap on the reward amount by limiting the actual incentive dollars to no more than 50 percent of the actual fuel savings.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Have the maximum allowed incentive dollars ever exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of your company's GPIF projection or actual filings in the period of 2005 through 2012? If so, please provide the year and the reasons.

A.

The maximum allowed incentive dollars have not exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of FPL's GPIF projection or actual filings in the period of 2005 through 2011. For 2012, although the projected maximum allowed incentive dollars did not exceed 50 percent of the maximum attainable fuel savings in the reward (penalty) table, the actual maximum allowed incentive dollars exceeded by 0.9 percent the maximum attainable fuel savings. This was due to higher than projected common equity monthly balances, which increased the dollar value of the 25 basis points maximum reward (penalty) for the January through December 2012 period.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Describe whether the linear scale and interpolation used by FPL in its reward (penalty) tables is based on data supporting the linear relationship or the need for simplicity. If applicable, please provide data that demonstrate the relationship between the performance levels and fuel savings.

A.

FPL uses the linear scale and interpolation because this is contemplated by the GPIF manual. FPL has not performed any data analysis to indicate the extent to which the linear scale and interpolation reflect the relationship between performance levels and fuel savings.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Based on the use of linear interpolation, should the reward (penalty) be capped at 50 percent of the fuel savings corresponding to the actual performance level in the reward (penalty) table by setting the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings? If not, please explain.

A.

FPL would have no objection to this proposed change, as FPL understands it, to set the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings in the reward (penalty) tables.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Should the existing minimum heat rate threshold of 75 Btu/kWh be modified, with a different number or a percentage based on the unit efficiency? As part of the response, please provide the data and analysis supporting your response.

A.

FPL does not believe that the existing minimum heat rate threshold of 75 Btu/kWh needs to be modified. As stated on page 3 of Order No. 9558 in Docket No. 800400-CI, the Commission decided "*to place a 'neutral band' of 75 Btu/kWh around the heat rate measurement to reflect the limitations upon accuracy inherent in such measurements.*" FPL believes the same limitations inherent in measuring the accuracy of predicting heat rate targets through the use of regression equations still exist and hence it is still appropriate to maintain a heat rate threshold of 75 Btu/kWh.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Should there be a similar minimum availability performance threshold for the GPIF reward (penalty)? As part of the response, please provide the data and analysis supporting your response.

A.

FPL does not believe that there should be a similar minimum availability performance threshold for the GPIF reward (penalty). As explained in the previous response, the heat rate threshold was established based on the accuracy limitations inherent to using regression curves to predict heat rate performance. Because availability performance projections are not based on regression equations, there are no comparable accuracy limitations in setting the availability targets and hence there is no need to establish such a threshold.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? As part of the response, please provide the data and analysis supporting your response.

A.

As stated in response to Interrogatory No. 46, FPL would have no objection to setting the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings in the reward (penalty). Otherwise, FPL does not believe that the reward (penalty) cap or the minimum threshold should be modified. FPL believes that the GPIF mechanism is working as originally intended. In fact, over the period 2005-2012 FPL customers have received fuel savings (net of GPIF rewards) totaling about $222 million, as shown on the table below.

Year	Net Fuel Savings* $000
2005	14,713
2006	40,907
2007	25,181
2008	44,682
2009	46,762
2010	11,814
2011	12,056
2012	25,683
Total	221,798

*Source: FPL GPIF True-up Filings 2005-2012 after Gas Adjustment Factor (GAF) removed. Refer to testimony of Carmine A. Priore filed October 1, 2010 in Docket 100001-EI. Figures for 2012 are pending Commission approval.

Q.

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 43-50.

Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? If so, provide data and analysis supporting such modification.

A.

Please see response to Interrogatory No. 49.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 7th day of August, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared J. Carine Bullock, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 43-50 from STAFF'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 43-50) in Docket No. 130001-EI, and that the responses are true and correct based on her personal knowledge.

J. Carine Bullock

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of August, 2013.

JAYNE LORING DAVIS
MY COMMISSION # DD908031
EXPIRES September 14, 2013
(407) 398-0153 FloridaNotaryService.com

Jayne Loring Davis
Notary Public
State of Florida, at Large

My Commission Expires:
9-14-13

60

FPL's Responses to Staff's Seventh Set of Interrogatories (Nos. 51-54)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 60
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0176-0181][Bates Nos. 0182-

Q.

For purposes of the following questions, please refer to the testimony of Terry J. Keith, dated August 2, 2013:

Page 6, Lines 16-21. Please explain why the 2013 actual/estimated burn for light oil is more than 1800% higher than in the Company's original projections.

A.

The 1800% variance in light oil consumption is primarily attributable to the testing of dual-fuel, combustion turbines. Light oil is primarily used as an emergency back-up fuel in case of any interruption to natural gas or during times when natural gas requirements exceed FPL's delivery capability due to extreme loads. As FPL's reliance on natural gas has increased, the necessity to be able to reliably swap combustion turbines to light oil has become increasingly imperative. Therefore, FPL has implemented a comprehensive testing program to continuously prove the reliability of the fuel oil systems and the capability of each dual-fuel combustion turbine to operate on 100% light oil. FPL did not include estimates for the consumption of light oil related to testing in its projections due to the difficulty associated with estimating these volumes, so all consumption for testing shows up as a variance from the projections.

Q.

For purposes of the following questions, please refer to the testimony of Terry J. Keith, dated August 2, 2013:

Page 7, Lines 1-4. Please explain why the 2013 actual/estimated burn for heavy oil is over 13% higher than in the Company's original projections.

A.

The 13% variance is primarily due to an increase in FPL's forecasted heavy oil consumption for the July through December period. FPL uses the POWRSYM model to project heavy oil consumption based on the model's economic dispatch of the system. For the July through December period, the model projected an increase in heavy oil consumption of 139,163 barrels from FPL's original projections. Over 92% of this projected increase occurs in the months of July and September. The projected increase in heavy oil consumption during these two months is caused by changes to several model input assumptions, including increases in load and economy sales, coupled with a decrease in economy purchases.

Q.

For purposes of the following questions, please refer to the testimony of Terry J. Keith, dated August 2, 2013:

Page 8, Lines 12-13. Please explain why the Energy Cost of Economy Purchases is "significantly lower than projected economy purchases."

A.

The significant decrease in the Energy Cost of Economy Purchases is primarily attributable to lower economy purchases. This decrease has been driven by several factors that have impacted FPL's position relative to the wholesale power market. For the six months of 2013, lower loads, less heavy oil consumption, the early commercial operation of the Cape Canaveral Next Generation Clean Energy Center (CCEC), and the overall efficiency and operation of FPL's fleet have pushed down FPL's marginal costs to the point that they are largely below market prices. During that period, FPL purchased 48,041 MWh of economy power compared to its original projection of 449,800 MWh, or 89.3% less economy purchases than originally projected. FPL believes that this trend will generally continue for the remainder of 2013 and is now forecasting economy purchases of 84,000 MWh for the July through December period compared to its original projections of 610,200 MWh for the same period, or a decrease of 86.2%. The combination of the actual period and estimated period variances compared to FPL's original projections results in an overall decrease in forecasted economy purchases of 87.5% which drives an overall decrease of 86.5% in the Energy Cost of Economy Purchases.

Q.

For purposes of the following questions, please refer to the testimony of Terry J. Keith, dated August 2, 2013:

Page 8, Line 21 through Page 9, Line 6. Please explain why the 2013 actual/estimated Energy Payments to Qualifying Facilities is 91% lower than in the Company's original projections.

A.

FPL's 2013 actual/estimated Energy Payments to Qualifying facilities are not 91% lower than the Company's original projections. The total variance of $39.4 million represents a decrease in Energy Payments to Qualifying Facilities of 27.5%. As stated in the Actual/Estimated True-Up testimony of Terry J. Keith, filed on August 2, 2013 in Docket No. 130001-EI, 91% of the $39.4 million cost variance is attributable to fewer MWh being purchased from QF facilities. Through the first six months of 2013, FPL purchased 526,625 MWh less from Cedar Bay, ICL and As-Available QF facilities. Approximately 55% of this decrease was due to lower than projected economic dispatch of the Cedar Bay and ICL facilities. The remaining 45% was due to fewer purchases from As-Available facilities. The actual/estimated modeling analysis for the July through December period resulted in a continuation of lower economic dispatch levels of Cedar Bay and ICL than FPL's original projections. FPL also lowered its projections for As-Available purchases for the remainder of 2013, based on updated actual data. Overall, FPL is projecting 798,438 MWh less in purchases from QF facilities for 2013. The remaining 9% of the $39.4 million variance is attributable to a slight reduction ($1.53/MWh) in the unit cost of QF purchases compared to FPL's original projections.

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 4th day of September, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 51-54 from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 51-54) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of September, 2013.

Notary Public
State of Florida, at Large

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

My Commission Expires:
May 30, 2017

61

FPL's Responses to Staff's Eighth Set of Interrogatories (Nos. 55-57)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 61
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0182-0186]

Q.

For the purpose of these interrogatories, please refer to Schedule E1-B, which is included in Appendix 1 of Exhibit TJK-3, attached to the testimony of FPL witness Terry J. Keith, filed on August 2, 2013.

According to Schedule E1-B (at Line 15, Column 14), FPL incurred $2,059,979 in Incremental Optimization Costs for the period January-December, 2013. Please identify what portion of these costs was:

a) from electric wholesale purchases;
b) from electric wholesale sales;
c) from the asset optimization functions listed below:

1) Gas storage utilization;
2) City-gate gas sales using existing transport;
3) Production area gas sales;
4) Capacity release of gas transportation;
5) Capacity release of electric transmission;
6) The outsourcing of the optimization function;
7) Any other optimization activity or function not listed above.

In each response to sub-part (a) through (c), state the total cost and include a breakdown between recurring or non-recurring components.

A.

As shown on Schedule E1-B (Lines 13 and 14), Incremental Optimization Costs fall into two categories: (1) incremental personnel, software, and hardware and (2) variable power plant O&M. Incremental personnel, software and hardware costs are allocated between optimization functions related to wholesale power transactions and natural gas transactions. Line 13 of Schedule E1-B shows total optimization costs for incremental personnel, software and hardware of $263,980 through December 2013. The allocation of these costs between wholesale power and natural gas optimization is shown below:

Optimization Function	Cost	Cost Type	Optimization Category
Wholesale Power	$195,583	Recurring	(a), (b), (c5)
Natural Gas	$68,397	Recurring	(c1), (c2), (c3), (c4), (c6), (c7)

Line 14 of Schedule E1-B shows total variable power plant O&M costs of $1,795,999. These costs are solely associated with electric wholesale sales and are considered non-recurring in the sense that they will vary from year to year depending on the level of FPL's wholesale sales compared to the threshold of 514,000 MWh (the level of such sales that were projected in FPL's 2013 Test Year).

Q.

For the purpose of these interrogatories, please refer to Schedule E1-B, which is included in Appendix 1 of Exhibit TJK-3, attached to the testimony of FPL witness Terry J. Keith, filed on August 2, 2013.

According to Schedule E1-B (at Line 13, Column 14), FPL incurred $263,980 for Incremental Personnel, Software, and Hardware Costs for the period January-December, 2013. Please identify what portion of these costs was:

a) incurred for Incremental Personnel;
b) incurred for Software;
c) incurred for Hardware;
d) incurred for any other optimization activity or function not listed above.

In each response to sub-part (a) through (d), state the total cost and include a breakdown between recurring or non-recurring components. Include in your response why FPL believes these costs are reasonable and prudent.

A.

The entire amount of $263,980 is for incremental personnel costs including salaries and employee-related expenses. The costs associated with incremental personnel are considered recurring. FPL believes these costs are reasonable and prudent as they are being incurred to generate additional benefits for customers under the Incentive Mechanism. A portion of these costs is related to one additional employee engaged in the asset optimization measures related to natural gas that are described in Paragraph 12(a)(ii) of the Stipulation and Settlement that was approved in Order No. PSC-13-0023-S-EI. Prior to 2013, FPL had not engaged in these types of natural gas asset optimization measures and therefore, the staff involved in natural gas procurement was not sufficient in size to perform both procurement and optimization functions. The additional employee is focused on delivering value to FPL's customers through the utilization of FPL's natural gas assets. The remaining portion of these costs is related to the addition of 1.5 employees in the power trading area. These employees complement the existing power trading staff and are focused on extracting incremental value for FPL's customers in the wholesale power market.

Q.

For the purpose of these interrogatories, please refer to Schedule E1-B, which is included in Appendix 1 of Exhibit TJK-3, attached to the testimony of FPL witness Terry J. Keith, filed on August 2, 2013.

According to Schedule E1-B (at Line 14, Column 14), FPL incurred $1,795,999 for Variable Power Plant O&M Costs over the 514,000 MW Threshold for the period January-December, 2013. Please identify what portion of these costs was:

a) incurred to implement its expanded short-term wholesale purchase programs;
b) incurred to implement its expanded short-term wholesale sales programs;
c) incurred to implement other asset optimization measures;
d) incurred for any other optimization activity or function not listed above.

In each response to sub-part (a) through (d), state the total cost and include a breakdown between recurring or non-recurring components. Include in your response why FPL believes these costs are reasonable and prudent.

A.

As described in response to Interrogatory No. 55, the amount of $1,795,999 for variable power plant O&M is solely related to wholesale power sales. The amount and timing of costs in this category are dependent on FPL's level of wholesale power sales compared to the threshold of 514,000 MWh and in that sense are considered non-recurring. These costs are reasonable and prudent as they represent incremental costs that FPL must incur to generate wholesale power sales beyond the 514,000 MWh of such sales that were projected in FPL's 2013 Test Year. The level of the costs was determined pursuant to the methodology set forth in Paragraph 12(b)(ii) of the Stipulation and Settlement that was approved in Order No. PSC-13-0023-S-EI, specifically: "such costs [are] determined by multiplying the sales above that threshold times the monthly weighted average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs."

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of September, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 55-57 from STAFF'S EIGHTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 55-57) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of September, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:
May 30th, 2017

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

62

FPL's Responses to Staff's Ninth Set of Interrogatories (Nos. 58-64)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 62
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0187-0195]

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Please describe what is involved in seismic and flooding walkdowns as described by the witness on page 4 at line 16 of his testimony.

A.

On March 12, 2012, the NRC asked U.S. nuclear power plants to perform a detailed inspection, or "walkdown," of their currently installed seismic and flooding protection features. The plants had to ensure the features met current requirements, and also identify, correct, and report any degraded conditions. The plants completed their walkdowns by November 2012; NRC inspectors have done follow-up inspections and the agency's technical experts are reviewing all these reports.

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Please provide the costs associated with FPL's re-evaluation of existing design features and development of strategies and conceptual design of modifications needed to satisfy the NRC Orders and RFIs.

A.

Total costs through August 31, 2013 associated with FPL's re-evaluation of existing design features and development of strategies and conceptual design of modifications are as follows:

2011	$ 41,573
2012	$3,892,088
YTD August 2013	$4,044,140
Total	$7,977,801

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Please explain what is meant by plant modifications and enhancements to support "beyond design basis" mitigation strategies as stated on Page 4, Lines 20-21.

A.

"Beyond design basis" mitigation strategies means the ability to implement strategies that will allow for the protection of the plant beyond the scope that a nuclear facility was designed and built. The NRC issued a Mitigation Strategies Order on March 12, 2012, requiring all U.S. nuclear power plants to implement strategies that will allow them to cope without their permanent electrical power sources for an indefinite amount of time. These strategies must keep the reactor core and spent fuel cool, as well as protect the thick concrete containment buildings that surround each reactor. The mitigation strategies are expected to use a combination of currently installed equipment (e.g., steam-powered pumps), additional portable equipment that is stored on-site, and equipment that can be flown in or trucked in from support centers.

The NRC is also requiring all operating reactor sites to use present-day information to re-evaluate the earthquake effects—or hazards—that could impact their site. These newly re-evaluated hazards, if worse than what the plant had originally calculated, will be analyzed to determine if plant structures, systems, and/or components need to be updated to protect against the new hazard. The NRC will review each step in the analysis process and take action to require plant changes as necessary.

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Please provide a list of the current regulatory deadlines described on page 5 of the witness's testimony.

A.

Implementation plans for the subject NRC Orders are required to be completed within two refueling cycles from 2/28/2013 or 12/31/2016, whichever is earlier. Currently those required dates are:

St Lucie 1	04/22/15
St Lucie 2	10/07/15
Turkey Point 3	11/04/15
Turkey Point 4	04/30/16

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Has FPL estimated a cost for the bulleted list on page 5 of the witness's testimony?

a. If yes, please provide FPL's estimates.

A.

FPL does not track the costs by the categories identified on the bulleted list on page 5 of the testimony and has not fully estimated the costs of the Fukushima Response Program at this time. However, FPL has identified a range of expected costs for the combined Turkey Point and St. Lucie effort which will fall within the categories identified on the bulleted list. The range is between $93M and $193M through the end of 2016. This estimate is for the cost of the proposed requirements in response to the immediate actions and does not include short term and long term requirements.

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Has FPL estimated a cost for the bulleted list on pages 6 and 7 of the witness's testimony?

a. If yes, please provide FPL's estimates.

A.

FPL does not track the costs by the bulleted list on pages 6 and 7 of the testimony. However, the estimated costs for the items included on the bulleted list on pages 6 and 7 of the referenced testimony is $13.2 million of capital and $227,000 of O&M.

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

On page 8 the witness describes the benefits of a third party cost estimating expert. The witness specifically details an instance in which a compliance alternative was accomplished at a reduced cost. Please provide the original cost and the lower cost of this compliance strategy.

A.

FPL's original estimate for electrical connections needed to support connection of portable generators at Turkey Point was $1,184,000. High Bridge provided an estimate of the same scope for $2,195,533. After further review, FPL revised their strategies to connect 4160VAC generators using portable cables vs. installed plug-in connections points. This revision reduced the projected cost from $1,184,000 to $350,000.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 18th day of September, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Don Grissette, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 58-64 from in STAFF'S NINTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 58-64) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Don Grissette

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of September, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:
March 08, 2014

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 8, 2014
Commission # DD 948300

63

FPL's Responses to Staff's Tenth Set of Interrogatories (Nos. 65-77)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 63
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0196-0219]

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for natural gas, please provide the following information in a schedule format:

(a) the transaction date (the date the swap was entered into) for the swap;
(b) the fixed price for the swap;
(c) the month or period in the future the swap is covering; and
(d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

A.

A schedule of natural gas hedging transactions, incorporating the transaction date, fixed price, transaction period, and NYMEX price is included in the attachment provided with this response. The forward prices represent the Henry Hub Natural Gas financial swap prices published by NYMEX.

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						-1.1%
						0.1%
						0.5%
						1.4%
						1.0%
						-0.5%
						0.2%
						1.1%
						0.6%
						0.8%
						0.7%
						0.1%
						-0.8%
						-0.1%
						0.5%
						1.2%
						-0.8%
						-0.2%
						0.7%
						-0.2%
						0.3%
						-0.9%
						-0.5%
						0.3%
						-0.1%
						0.4%
						0.2%
						0.4%
						0.4%
						-0.6%
						0.0%
						0.0%
						0.8%
						0.7%
						0.7%
						0.2%
						-0.2%
						0.0%
						0.6%
						0.6%
						0.1%
						-0.1%
						1.8%
						0.3%
						0.5%
						0.2%
						1.1%
						-0.4%
						1.9%
						-0.2%
						-1.4%
						0.6%
						1.2%
						1.5%
						-0.2%
						-0.4%
						0.7%
						0.3%
						0.3%
						0.5%
						0.2%
						1.3%

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						-0.1%
						-0.6%
						0.5%
						0.7%
						0.5%
						0.4%
						0.7%
						-0.3%
						0.0%
						0.8%
						0.3%
						0.2%
						-0.1%
						-3.5%
						-1.8%
						-0.7%
						-0.2%
						-0.5%
						0.2%
						1.0%
						0.5%
						0.2%
						0.1%
						-0.7%
						0.0%
						0.6%
						1.4%
						0.6%
						0.2%
						-0.4%
						0.4%
						0.3%
						-1.3%
						0.1%
						-3.1%
						0.2%
						0.1%
						-0.5%
						-1.8%
						-1.2%
						0.3%
						-1.4%
						-1.9%
						-0.3%
						0.5%
						0.1%
						0.2%
						-0.2%
						3.2%
						-0.5%
						0.7%
						-1.0%
						0.0%
						0.8%
						0.0%
						0.2%
						0.1%
						0.0%
						0.8%
						-0.2%
						-0.2%
						-0.6%

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						0.1%
						0.3%
						-0.2%
						0.4%
						0.1%
						0.3%
						-0.6%
						-0.1%
						0.3%
						-0.9%*
						-0.0%*
						-2.0%
						-0.4%
						0.0%
						2.3%
						-0.1%*
						0.9%
						0.2%
						-0.4%
						-0.4%
						0.2%
						-0.1%*
						-0.1%
						0.2%
						-0.5%
						1.2%
						0.0%
						-0.4%
						1.4%
						-1.5%
						-0.8%
						1.4%
						-1.2%
						0.2%
						0.3%
						-0.1%
						0.0%
						0.2%
						-0.2%
						-1.7%
						-0.2%
						-0.3%
						-0.2%
						0.6%
						0.1%*
						0.0%
						0.0%
						-0.8%
						-0.5%
						-0.2%
						-0.2%
						-0.6%
						0.6%
						-0.5%
						0.3%
						-0.6%
						0.0%
						1.2%
						-1.2%
						-0.6%
						-0.8%
						-0.2%

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
						0.8%
						0.9%
						-0.7%
						-0.3%
						1.0%
						0.3%
						2.1%
						0.4%
						0.5%
						-1.1%
						-1.3%
						-0.7%
						-0.4%
						-0.1%
						0.2%
						0.4%
						0.2%
						0.3%
						0.7%
						-0.3%
						0.0%
						0.3%
						-0.1%
						0.0%
						0.2%
						-0.8%
						0.2%
						-0.9%*
						-0.0%*
						-0.1%*
						-0.1%*
						0.1%*
						-1.2%
						-0.4%
						0.0%
						0.1%
						-0.5%
						0.3%
						0.6%
						0.5%
						-0.5%
						0.4%
						-0.3%
						-0.5%
						1.1%
						-1.3%
						0.2%
						-0.4%
						0.7%
						-0.6%
						-1.2%
						0.1%
						-0.2%
						0.4%
						1.2%
						-1.4%
						0.7%
						0.6%
						0.6%
						0.2%
						0.3%
						0.5%

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						1.4%
						1.9%
						0.9%
						-0.1%
						-2.1%
						-1.2%
						-1.0%
						0.3%
						0.1%
						-0.4%
						-0.6%
						0.2%
						0.5%
						2.3%
						0.5%
						-0.2%
						-0.6%
						1.2%
						0.0%
						-0.5%
						0.0%
						0.5%
						0.0%
						-1.3%
						-0.1%
						-0.2%
						-0.7%
						0.3%
						-0.6%
						-0.6%
						-1.6%
						-0.4%
						0.4%
						-0.2%
						-0.9%
						-0.3%
						-0.8%
						0.1%
						-0.3%
						-0.5%
						0.5%
						1.0%
						0.0%
						2.0%
						0.9%
						0.6%
						0.1%
						0.4%
						0.1%
						1.1%
						1.0%
						-1.5%
						-1.0%
						1.1%
						1.0%
						0.2%
						0.4%
						-1.8%
						-0.1%
						0.5%
						0.0%
						0.2%

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						-0.1%
						0.1%
						-0.6%
						0.1%
						-0.1%
						0.2%
						0.5%
						0.4%
						-0.6%
						0.6%
						-0.7%
						0.0%
						0.0%
						0.4%
						0.7%
						-0.8%
						0.3%
						-0.8%
						2.6%
						0.7%
						-0.2%
						-0.5%
						0.0%
						0.4%
						1.4%
						0.4%
						-0.4%
						1.3%
						-0.1%
						0.6%
						-0.6%
						0.3%
						-3.7%
						-1.6%
						-0.3%
						1.8%
						0.6%
						-1.2%
						-0.5%
						-0.6%
						1.5%
						-0.1%
						-0.2%
						0.1%
						0.8%
						0.4%
						1.6%
						-1.3%
						-1.8%
						-1.0%
						-0.9%
						0.0%
						-0.1%
						-0.5%
						-0.4%
						2.5%
						0.2%
						0.4%
						1.1%
						0.3%
						0.0%
						0.0%

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - NATURAL GAS TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						-0.1%
						-1.0%
						-0.7%
						-0.3%
						0.0%
						-0.2%
						0.9%
						0.5%
						0.0%
						0.4%
						-0.1%
						1.0%
						0.3%
						1.4%
						0.4%
						0.6%
						0.4%
						2.0%
						0.0%
						0.0%
						0.4%
						0.0%
						0.0%
						0.6%
						0.2%
						0.2%
						1.1%
						1.8%
						2.2%
						0.5%
						0.2%
						0.1%
						1.9%
						0.7%
						0.3%
						-1.2%
						-0.2%
						0.8%
						0.7%
						0.4%
						-0.1%
						1.2%
						0.0%
						0.4%
						-2.5%
						-2.8%
						0.4%

(*) Note: These deals were originally executed as 12-month strip transactions. The December component was transferred to an affiliate of the counterparty, with the same terms and conditions as originally executed, prior to settlement. The fixed price vs. NYMEX closing price calculations use closing values from the dates on which the transactions were originally executed.

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for fuel oil, please provide the following information:

(a) the transaction date (the date the swap was entered into) for the swap;
(b) the fixed price for the swap;
(c) the month or period in the future the swap is covering; and
(d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

A.

A schedule of fuel oil hedging transactions, incorporating the transaction date, fixed price, transaction period, and NYMEX price is included in the attachment provided with this response. The forward prices represent New York Harbor Residual Fuel Oil 1.0 % Sulfur financial swap prices published by NYMEX.

AUGUST 1, 2012 - JULY 31, 2013 HEDGING PROGRAM - FUEL OIL TRANSACTIONS

Portfolio	Trade Date	Deal Start Date	Deal End Date	Fixed Price	NYMEX Closing Price	Fixed Price vs NYMEX Price
[redacted]						-0.8%
						-1.0%
						-3.8%
						-1.7%
						-0.7%
						-4.5%
						-2.1%
						-0.4%
						-0.1%
						-2.5%
						-2.7%
						0.5%
						1.5%
						0.2%
						0.3%
						0.3%
						0.3%
						0.0%
						-0.4%
						-0.3%
						-0.7%

Q.

For interrogatories 65 and 66 above, please explain the difference, if any, between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

A.

The differences between the fixed price and the corresponding NYMEX swap price for all natural gas hedge transactions for the period from August 1, 2012 through July 31, 2013 were less than 5 percent of the swap fixed prices. The calculations are included as part of the response to interrogatory no. 65.

The differences between the fixed price and the corresponding NYMEX swap price for all fuel oil hedge transactions for the period from August 1, 2012 through July 31, 2013 were less than 5 percent of the swap fixed prices. The calculations are included as part of the response to interrogatory no. 66.

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with options for natural gas prices, please provide the following information in a schedule format.

(a) the transaction date for the option;
(b) the option price or premium;
(c) the type of option;
(d) the time to expiration; and
(e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

A.

FPL's Hedging/Risk Management plan did not include natural gas option transactions for either 2012 or 2013.

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with options for fuel oil prices, please provide the following information in a schedule format.

(a) the transaction date for the option;
(b) the option price or premium;
(c) the type of option;
(d) the time to expiration; and
(e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

A.

FPL's Hedging/Risk Management plan did not include fuel oil option transactions for either 2012 or 2013.

Q.

For interrogatories 68 and 69 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

A.

FPL's Hedging/Risk Management plan did not include natural gas or fuel oil option transactions for either 2012 or 2013.

Q.

Please state the realized hedging savings and costs by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2012, and ending July 31, 2013.

A.

The realized hedging gains and losses by fuel type and by type of hedging instrument for the period from August 1, 2012 to December 31, 2012 are included in the August 2012 Through December 2012 Hedging Activity True-Up Report, filed in Docket No. 130001-EI on April 5, 2013. The realized hedging gains and losses by fuel type and by type of hedging instrument for the period from January 1, 2013 through July 31, 2013 are included in the Fuel Hedging Activity Report, filed in Docket No. 130001-EI on August 16, 2013.

Q.

For the twelve months beginning August 1, 2012 and ending July 31, 2013, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in FPL's risk management plan or otherwise stated in internal procedures governing FPL's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

A.

All hedged volumes of heavy fuel oil and natural gas, for the twelve months beginning August 1, 2012 and ending July 31, 2013, were within approved percentage ranges as stated in FPL's Risk Management Plan(s) and internal procedures governing FPL's hedging activities.

Q.

Please provide a comparison of FPL's Risk Management Plans for 2013 and 2014. Please describe any changes between these respective plans.

A.

There are no significant differences between the 2013 and 2014 Risk Management Plans. Minor changes were made to incorporate routine updates to the Trading and Risk Management Procedures and Energy Trading and Risk Management Policy. The latest changes were made to clarify Risk Management policies and procedures that specifically apply to the Energy Marketing and Trading Division.

All hedging parameters in the 2014 Risk Management Plan (hedge percentages, execution window, hedge tenure) for natural gas are consistent with those outlined in the 2013 Risk Management Plan. The 2014 Risk Management Plan includes an updated overview of the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Q.

For open hedging transactions since August 1, 2012, has FPL experienced any defaults by a counter-party? Please identify the counter-party and explain.

A.

FPL has not experienced any counterparty defaults related to open hedging transactions since August 1, 2012.

Q.

For all currently open hedging transactions, does FPL have any concern regarding default by a counter-party for any specific transaction? Please identify the counter-party and explain.

A.

FPL does not have any specific counterparty credit concerns related to current open hedging transactions.

Q.

Since January 1, 2012, has FPL stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? Please identify the counter- party and explain.

A.

FPL stopped engaging in hedging transactions with any of its hedging counterparties due to credit risk concerns since January 1, 2012.

Q.

Has FPL incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If so, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

A.

Any savings or costs associated with FPL's hedging program are included in the total fuel expense, which is recovered through FPL's fuel clause in the period realized. Any difference between the amounts realized and the amounts forecasted are adjusted in the over or under fuel recoveries and no specific tax effect is provided for any realized hedging cost. Since FPL does not report any income associated with its cost of fuel used in generation, FPL does not incur any federal and/or state tax expenses (credits) or have any deferrals related to any savings or costs related to its hedging program.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 7th day of October, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 65 through 76 from in STAFF'S TENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 65-77) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of October, 2013.

Notary Public
State of Florida, at Large

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

My Commission Expires:
May 30, 2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 10th day of October, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Elizabeth Fuentes, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 77 from in STAFF'S TENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 65-77) in Docket No. 130001-EI, and that the response is true and correct based on her personal knowledge.

Elizabeth Fuentes

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10th day of October, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

64

FPL's Responses to OPC's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 64
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0220-0266]

Q.

Interrogatories 1 through 5 relate to the August 2, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Please provide a list of all references to any and all testimony, exhibits, and discovery responses from Docket No. 120015-EI which address or include the capital (plant and construction work in progress) and O&M expenditures included in the 2013 Test Year in Docket No. 120015-EI described by the witness on page 16 at line 24 to page 17, line 1 of his testimony.

A.

1. OPC's 11th set of interrogatories, question # 237
2. OPC's 11th set of PODs, request #96
3. Art Stall's Errata
4. Testimony of Art Stall, Docket No. 120015-EI
5. Staff's 19th set of interrogatories # 476

Q.

Interrogatories 1 through 5 relate to the August 2, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Please provide the actual and budgeted dollar amounts of capital and O&M expenditures incurred by project description related to the NRC requirements resulting from the Fukushima event for 2011 and 2012. Include a description of whether any capital amounts were recorded in construction work in progress as of the end of 2013 to be capitalized after 2012.

A.

O&M:

2011 - $41,573 Actual	Budget $0
2012 - $1,854,892 Actual	Budget $474,000

Capital:

2011 - $0 Actual	Budget $0
2012 - $883,196 Actual	Budget $5,085,250

Deferred:
2012 - $1,154,000 Actual

Capital expenditures of $883,196 incurred in 2012 were recorded to plant-in-service before 12/31/12. No amounts were recorded in construction work in progress as of the end of 2012.

Q.

Interrogatories 1 through 5 relate to the August 2, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Refer to the 2013 actual and current estimate to complete for NRC compliance costs related to the Fukushima event on page 19, lines 19-21 of $227,000 of O&M expenses and $13.2 million of capital expenditures. Please provide a breakdown and a description by amounts of all capital and O&M expense costs incurred as of August 31, 2013, related to the NRC compliance costs resulting from the Fukushima event.

A.

Capital	19,717
Deferred:	
Flooding Walkdown/Evaluation	2,553,556
Seismic Walkdown/Evaluation	62,974
Flex	1,181,723
Spent Fuel Pool Instrumentation	70,362
Other	816
Total Deferred	3,869,430
O&M	154,992
Total	4,044,140

Q.

Interrogatories 1 through 5 relate to the August 2, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Refer to the 2013 actual and current estimate to complete for NRC compliance costs related to the Fukushima event on page 19, lines 19-21 of $227,000 of O&M expenses and $13.2 million of capital expenditures. Please provide a breakdown and description by amounts of all capital and O&M expense costs budgeted to be completed from September 1, 2013 to December 31, 2013.

A.

Refer to OPC's First Set of PODs No. 3.

Q.

Questions 1 through 4 relate to the August 2, 2013, testimony of Don Grissette filed in Docket No. 130001-EI.

Please provide a copy of the documents that reflect the 2013 and 2014 budget reports for the Nuclear Operating Unit that include the capital and O&M expense for the projects associated with the NRC compliance costs related to the Fukushima event incurred since 2012.

A.

See documents attached to this response. Documents responsive to this request are provided as Bates Nos. FCR-13-192 through FCR-13-198.

Fukushima
Estimated 2014 O&M

	January	February	March	April	May	June	July	August	September	October	November	December	Total
St. Lucie	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000
Turkey Point	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000
Total	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	400,000

Project : PSL - Fukushima Project

Data Supplied By : Michael McCabe

Phone Number : 772-429-7932 Date : 06/05/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Description	Plant Location	Unit Number	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014	
1		UNUC.00000736.90	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	1	321.0	8/30/2014	Addition	195,930	167,310	178,989	171,421	171,421	183,101	171,421	171,421	183,101	179,644	182,135	193,815	2,149,709	
2		UNUC.00000736.91	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	2	321.0	12/31/2014	Addition	195,930	167,310	178,989	171,421	171,421	183,101	171,421	171,421	183,101	179,644	182,135	193,815	2,149,709	
3		UNUC.00000736.92	NEW STORAGE BUILDING	St. Lucie	Common	321.0	3/31/2015	Addition	458,150	458,150	470,650	462,550	462,550	475,050	462,550	462,550	475,050	536,350	539,017	551,517	5,814,133	
4		UNUC.00000736.90	ELECTRICAL MODS COMPLETED PSL1_26	St. Lucie	1	321.0	4/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533	
5		UNUC.00000736.90	MECHANICAL MODS COMPLETED PSL1_26	St. Lucie	1	321.0	4/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533	
6		UNUC.00000736.90	FLOODING	St. Lucie	1	321.0	4/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546	
7		UNUC.00000736.90	SEISMIC	St. Lucie	1	321.0	4/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546	
8		UNUC.00000736.92	PORTABLE EQUIP	St. Lucie	Common	321.0	4/30/2015	Addition	-	-	-	-	-	-	-	-	-	-	-	4,279,718	4,279,718	
9		UNUC.00000736.91	ELECTRICAL MODS COMPLETED PSL2_22	St. Lucie	2	321.0	11/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533	
10		UNUC.00000736.91	MECHANICAL MODS COMPLETED PSL2_22	St. Lucie	2	321.0	11/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533	
11		UNUC.00000736.91	FLOODING	St. Lucie	2	321.0	11/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546	
12		UNUC.00000736.91	SEISMIC	St. Lucie	2	321.0	11/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546	
13		UNUC.00000736.92	SAFER POOLED EQUIPMENT INTANGIBLE ASSET	St. Lucie	Common	321.0	12/31/2015	Addition	422,236	14,104	22,630	15,572	12,386	7,490	12,502	7,644	21,840	14,358	7,482	6,474	564,720	
14									1,594,541	1,184,695	1,202,694	1,117,636	1,114,452	1,174,554	1,228,733	1,223,875	1,341,404	1,439,588	1,429,379	5,794,756	19,846,305	
15																					2,682,931	FPL Payroll
16																					17,163,374	Net of payroll

130001 Hearing Exhibits - 00227

Project : PSL - Fukushima Project

Data Supplied By : Michael McCabe

Phone Number : 772-429-7632 Date : 08/05/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Description	Plant Location	Unit Number	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1		UNUC.00000736.90	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	1	322.0	8/30/2014	Addition	152,532	123,911	135,561	128,023	128,023	139,702	128,023	128,023	139,702	136,245	136,737	150,416	1,626,927
2		UNUC.00000736.91	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	2	322.0	12/31/2014	Addition	152,532	123,911	135,561	128,023	128,023	139,702	128,023	128,023	139,702	136,245	136,737	150,416	1,626,927
3		UNUC.00000736.92	NEW STORAGE BUILDING	St. Lucie	Common	321.0	3/31/2015	Addition	424,900	424,900	437,400	429,300	429,300	441,800	429,300	429,300	441,800	503,100	505,767	518,267	5,415,133
4		UNUC.00000736.90	ELECTRICAL MODS COMPLETED PSL1_26	St. Lucie	1	324.0	4/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
5		UNUC.00000736.90	MECHANICAL MODS COMPLETED PSL1_26	St. Lucie	1	322.0	4/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
6		UNUC.00000736.90	FLOODING	St. Lucie	1	321.0	4/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
7		UNUC.00000736.90	SEISMIC	St. Lucie	1	321.0	4/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
8		UNUC.00000736.92	PORTABLE EQUIP	St. Lucie	Common	325.0	4/30/2015	Addition	-	-	-	-	-	-	-	-	-	-	-	4,279,716	4,279,716
9		UNUC.00000736.91	ELECTRICAL MODS COMPLETED PSL2_22	St. Lucie	2	324.0	11/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
10		UNUC.00000736.91	MECHANICAL MODS COMPLETED PSL2_22	St. Lucie	2	324.0	11/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
11		UNUC.00000736.91	FLOODING	St. Lucie	2	322.0	11/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
12		UNUC.00000736.91	SEISMIC	St. Lucie	2	321.0	11/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
13		UNUC.00000736.92	SAFER POOLED EQUIPMENT INTANGIBLE ASSET	St. Lucie	Common	303.0	12/31/2015	Addition	422,236	14,104	22,630	15,572	12,366	7,490	12,502	7,644	21,840	14,358	7,482	6,474	564,720
14									**1,367,963**	**958,118**	**976,116**	**895,058**	**891,674**	**951,976**	**1,006,155**	**1,001,297**	**1,118,826**	**1,217,011**	**1,206,801**	**5,572,178**	**17,163,374**
15																					-
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130001 Hearing Exhibits - 00228

Project : PSL - Fukushima Project

Data Supplied By : Michael McCabe

Phone Number : 772-429-7932 Date : 08/05/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Description	Plant Location	Unit Number	Payroll	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1		UNUC.00000736.90	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	1	FPL	321.0	8/30/2014	Addition	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	520,782
2		UNUC.00000736.91	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	2	FPL	321.0	12/31/2014	Addition	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	520,782
3		UNUC.00000736.92	NEW STORAGE BUILDING	St. Lucie	Common	FPL	321.0	3/31/2015	Addition	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	399,000
4		UNUC.00000736.90	ELECTRICAL MODS COMPLETED PSL1_26	St. Lucie	1	FPL	321.0	4/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
5		UNUC.00000736.90	MECHANICAL MODS COMPLETED PSL1_26	St. Lucie	1	FPL	321.0	4/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
6		UNUC.00000736.90	FLOODING	St. Lucie	1	FPL	321.0	4/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
7		UNUC.00000736.90	SEISMIC	St. Lucie	1	FPL	321.0	4/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
8		UNUC.00000736.91	ELECTRICAL MODS COMPLETED PSL2_22	St. Lucie	2	FPL	321.0	11/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
9		UNUC.00000736.91	MECHANICAL MODS COMPLETED PSL2_22	St. Lucie	2	FPL	321.0	11/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
10		UNUC.00000736.91	FLOODING	St. Lucie	2	FPL	321.0	11/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
11		UNUC.00000736.91	SEISMIC	St. Lucie	2	FPL	321.0	11/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
										226,578	226,578	226,578	222,578	222,578	222,578	222,578	222,578	222,578	222,578	222,578	222,578	2,682,931

130001 Hearing Exhibits - 00229

Project : Fukushima

Data Supplied By : Christine Randell

Phone Number : 305-246-7343 Date : 09/02/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Plant Location	Unit Number	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1	Flood	UNUC.00000742.02.01	Turkey Point	Common	321.0	Sep-16	Addition	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,072	241,400
2	Seismic	UNUC.00000742.03.01	Turkey Point	Common	321.0	Jun-16	Addition	5,226	5,226	5,238	72,420	72,420	72,420	72,420	72,420	72,420	0	0	0	450,211
3	Flex	UNUC.00000742.04.01	Turkey Point	Common	322.0	Sep-16	Addition	584,510	584,510	584,510	513,780	513,780	513,780	840,342	840,342	840,342	759,875	759,875	759,875	8,095,521
5	Spent Fuel	UNUC.00000742.05.01	Turkey Point	Common	322.0	Jun-16	Addition	42,969	42,969	42,969	42,969	42,969	42,969	222,088	222,088	222,088	222,088	222,088	222,088	1,590,343
6																				0
7																				0
8																				0
9																				0
10																				0

costs														
flooding	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,630	200,000
seismic	4,330	4,330	4,340	60,000	60,000	60,000	60,000	60,000	60,000	0	0	0	373,000
flex	588,600	588,600	588,600	530,000	530,000	530,000	815,029	815,029	815,029	748,362	748,362	748,362	8,045,972
sfp	35,000	35,000	35,000	35,000	35,000	35,000	175,000	175,000	175,000	175,000	175,000	175,000	1,260,000
													9,878,972
allocations													
flooding	0	0	0	0	0	0	0	0	0	0	0	0	0
seismic	0	0	0	0	0	0	0	0	0	0	0	0	0
flex	10,000	10,000	10,000	10,000	10,000	10,000	15,000	15,000	15,000	15,000	15,000	15,000	150,000
sfp	600	600	600	600	600	600	9,000	9,000	9,000	9,000	9,000	9,000	57,600
													207,600
contingency													
flooding	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,442	41,400
seismic	696	696	698	12,420	12,420	12,420	12,420	12,420	12,420	0	0	0	77,211
flex	123,910	123,910	123,910	111,780	111,780	111,780	171,816	171,816	171,816	158,016	158,016	158,016	1,866,566
sfp	7,369	7,369	7,369	7,369	7,369	7,369	38,088	38,088	38,088	38,088	38,088	38,088	272,743
													2,087,920
total													
flooding	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,072	241,400
seismic	5,226	5,226	5,238	72,420	72,420	72,420	72,420	72,420	72,420	0	0	0	450,211
flex	722,510	722,510	722,510	651,780	651,780	651,780	1,001,845	1,001,845	1,001,845	921,378	921,378	921,378	9,912,538
sfp	42,969	42,969	42,969	42,969	42,969	42,969	222,088	222,088	222,088	222,088	222,088	222,088	1,590,343
													12,174,492
Flex payroll $													
mech eng	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	420,000
mech impl	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000
elec eng	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	16,000
bldg eng	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	40,000
bldg impl	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000
wells eng	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	180,000
wells impl	0	0	0	0	0	0	16,667	16,667	16,667	16,667	16,667	16,667	100,000
RCP seals eng	0	0	0	0	0	0	6,836	6,836	6,836	6,836	6,836	6,836	41,017
overall support	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000
	138,000	138,000	138,000	138,000	138,000	138,000	161,503	161,503	161,503	161,503	161,503	161,503	1,797,017

130001 Hearing Exhibits - 00230

Author: JKC/BHV

Status of Data: 01/31/2012 10:31:52

Chart | Filter | Information

Resp. cost cntr	WBS Reporting WBS		WBS Project type	Time Fiscal year/period	YE WV1 -Working Version JAN 2013 to DEC 2013													
[redacted] Shinkuh Okada	UNUC.00000736.01.91	POST FUKUSHIMI DABC	C	Capital WBS Element	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013	July 2013	August 2013	September 2013	October 2013	November 2013	December 2013	Overall Result	
	UNUC.00000742.01.91	PTN Post Japan Initiative (Capital)	C	Capital WBS Element			$ 24,934.48	$ 7,990.81	$ 16,267.76	$ 6,749.51		$ 1,493,352.26	$ 1,615,112.28	$ 1,883,846.56	$ 1,909,694.34	$ 8,533,280.24		
	UNUC.00000736.02.91	PBL Fukushima Flooding Walkdown/Eval	D	Deferred	$ 395,874.56	$ 85,407.17	$ 88,421.97	$ 21,248.63	$ 209,584.45	$ 190,669	$ 179,917.80	$ 186,190.06	$ 982,087.50	$ 340,867.92	$ 432,668.14	$ 2,864,218.49	$ 4,685,636.32	
	UNUC.00000736.03.91	PBL Fukushima Seismic Walkdown/Eval	D	Deferred	$ 3,292.85	$ 7,876.99	$ 1,291.31			$ 398,583.35						$ (1,223,671.94)	$ (23,441.21)	
	UNUC.00000736.04.91	PBL Fukushima FLEX Strategies	D	Deferred						$ 4,519.58							$ 16,980.74	
	UNUC.00000742.02.91	PTN Fukushima Flooding Walkdown/Eval	D	Deferred	$ 6,476.07	$ 285,738.68	$ 36,091.80	$ 1,817.80		$ 5,480.47						$ (308,926.45)	$ 5,463.47	$ 0.00 Deferred
	UNUC.00000742.03.91	PTN Fukushima Seismic Walkdown/Eval	D	Deferred	$ 203.51	$ 140.27	$ 198.40	$ 3,182.63								$ (3,734.21)	$ 0.00	
	UNUC.00000742.04.91	PTN Fukushima Flex Mitigation Strategies	D	Deferred	$ 165,838.95	$ 125,557.64	$ 74,869.00	$ 76,445.21	$ 152,317.89	$ 161,764.87						$ (780,523.65)	$ 0.00	
	UNUC.00000742.05.91	PTN Fukushima Spent Fuel Pit Instruments	D	Deferred		$ 4,809.80	$ 19,222.74	$ 15,068.42	$ 6,264.51	$ 680.56						$ (46,035.97)	$ 0.00	
	UNUC.00000740.01.91	PBL Post Japan Initiative	E	Expense WBS Element	$ 24,352.16	$ 27,558.89	$ (7,997.41)	$ 13,467.29	$ 20,147.56	$ 17,410.82	$ 5,031.14						$ 100,000.45	
	UNUC.00000741.01.91	Post Japan Initiative	E	Expense WBS Element	$ 12,826.43	$ 150,351.21	$ (17,288.58)	$ 44,813.74)	$ 15,502.35	$ (86,881.70)	$ 9,373.00	$ 8,873.00	$ 58,873.00	$ 8,873.00	$ 8,873.00	$ (44,471.00)	$ 126,999.93	
	Result				$ 636,866.53	$ 676,350.85	$ 219,803.71	$ 157,216.53	$ 420,804.81	$ 507,866.72	$ 194,321.94	$ 1,848,415.32	$ 2,656,052.76	$ 1,964,852.28	$ 2,426,387.80	$ 1,987,448.71	$ 13,445,805.84	
					$ 0.00	$ 0.00	$ 24,934.48	$ 7,990.81	$ 16,267.76	$ 6,558.82	$ 179,917.80	$ 1,539,542.32	$ 2,597,179.76	$ 1,855,778.28	$ 2,416,814.89	$ 4,374,110.83	$ 13,219,805.56	Estimated 2013 Capital
																	$ (10,000,000)	Rate Case Forecast
																	$ 3,219,805.56	Estimated Incremental Capital
					$ 37,178.56	$ 186,820.10	$ (36,286.05)	$ 6,883.66	$ 35,848.91	$ (71,479.88)	$ 14,404.14	$ 8,873.00	$ 58,873.00	$ 8,873.00	$ 8,873.00	$ (44,471.00)	$ 227,000.39	Estimated 2013 O&M
																	$ (144,000.00)	Test Year O&M
																	$ 83,000.39	Estimated Incremental O&M

130001 Hearing Exhibits - 00231

Budget Variance Report (AFa/PYA)

Author JKC0HWV Status of Data 01/31/2012 10:31:52

Chart | Filter | Information

Table

Resp. cost cntr		WBS:Project type		WBS-Reporting WBS		YTD Current App Bgt Edit JAN 2013 to DEC 2013
20105	Nuclear Division	C	Capital WBS Element	UNUC.00000736.01.01	POST FUKUSHUMI DAIIC	$ 8,532,754.11
				UNUC.00000742.01.01	PTN Post Japan Initiative (Capital)	$ 5,501,395.20
		E	Expense WBS Element	UNUC.00000740.01.01	PSL Post Japan Initiative	$ 100,000.00
				UNUC.00000741.01.01	Post Japan Initiative	$ 72,000.00
		Result				$ 14,206,149.31

130001 Hearing Exhibits - 00232

Q.

Witness J. A. Stall's direct testimony filed in Docket 120015-EI on page 21, lines 14-16, states that FPL included O&M and capital costs of $144,000 and $2.5 million, respectively, in the 2013 test year related to the Fukushima requirements. By letter dated August 16, 2012 FPL submitted errata sheets to J.A. Stall's direct testimony and two of his exhibits. On this errata sheet, Mr. Stall changed his testimony on page 21, line 14 from $2.5 to $5.0 million, which reflects the amount of capital plant that FPL included in the 2013 test year. Please explain why this change was made and whether the $2.5, $5.1 or 10.0 million was included in the MFR schedules when the company filed its rate case. Please include all references to show where these amounts are reflected in the MFRs if not provided in FPL's response to OPC's Interrogatory No. 2.

A.

Witness Stall filed an errata to his direct testimony in Docket No. 120015-EI in order to state the proper amount of forecasted capital expenditures associated with the Fukushima requirements for the year 2013. Witness Stall originally reflected forecasted capital expenditures for one of FPL's nuclear sites in his testimony when he should have reflected the forecasted amount for both of FPL's sites. As such, an errata was filed to change Witness Stall's testimony in order to reflect the total forecasted capital costs of $5.1 million for the year 2103. This amount, $5.1 million, represents the amount of capital expenditures forecasted for 2013 only and does not represent the total amount included in rate base in FPL's 2013 Test Year. FPL forecasted $5.1 million of capital expenditures for this project for both 2012 and 2013, and therefore, forecasted a total capital project cost at year-end 2013 of $10 million (rounded).

As stated in FPL's response to OPC's First Set of Interrogatories, Question No. 1, FPL included the accumulated $10 million of capital costs associated with this project in its rate base for the 2013 Test Year in CWIP and/or plant-in-service. As such, the $10 million of capital costs are reported on MFR B-6, Page 4 of 13, Line 14 (CWIP) and/or MFR B-6, Page 1 of 13, Line 27 (plant-in-service). The forecasted O&M expenses of $144,000 included in the 2013 Test Year was as follows: $72,000 on MFR C-4, Page 4 of 13, Line 7, and $72,000 on MFR C-4, Page 4 of 13), Line 12.

Q.

The following interrogatories relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Please state whether any additional NRC orders on the subject of Fukushima-related requirements have been issued since the March 2012 orders described on page 3, line 8-10 of Mr. Grissette's testimony.

A.

There were no new NRC Orders on the subject of Fukushima-related requirements issued since March 2012.

Q.

The following interrogatories relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Please identify all 2012, 2013, 2014 budget documents relied upon for the inclusion of $144,000 and $2.5 million in relation to anticipated new Fukushima-related requirements.

A.

O&M Budget Horizon Report and 5 Year Capital Forecast report. Also, refer to OPC's First Set of Interrogatories No. 2. There were no 2014 budget documents relied upon for the inclusion of $144,000 and $2.5 million.

Q.

The following interrogatories relate to the August 30, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Refer to page 12, line 15 to page 13, line 2. Please provide a breakdown of all 2014 costs requested to be recovered in the capacity clause related to the 2012 NRC Order and RFIs pertaining to the Fukushima event.

A.

Refer to OPC's First Set of PODs No. 3.

Q.

Questions 1 through 4 relate to the August 2, 2013, testimony of Don Grissette filed in Docket No. 130001-EI.

Please provide a copy of the documents that reflect the 2013 and 2014 budget reports for the Nuclear Operating Unit that include the capital and O&M expense for the projects associated with the NRC compliance costs related to the Fukushima event incurred since 2012.

A.

See documents attached to this response. Documents responsive to this request are provided as Bates Nos. FCR-13-192 through FCR-13-198.

Fukushima
Estimated 2014 O&M

	January	February	March	April	May	June	July	August	September	October	November	December	Total
St. Lucie	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000
Turkey Point	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000
Total	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	33,333	400,000

130001 Hearing Exhibits - 00238

Project : PSL - Fulaushins Project

Data Supplied By : Michael McCabe

Phone Number : 772-429-7932 Date : 06/05/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Description	Plant Location	Unit Number	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1		UNUC.00000736.90	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	1	321.0	8/30/2014	Addition	195,930	167,310	178,989	171,421	171,421	183,101	171,421	171,421	183,101	179,644	182,135	193,815	2,149,709
2		UNUC.00000736.91	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	2	321.0	12/31/2014	Addition	195,930	167,310	178,989	171,421	171,421	183,101	171,421	171,421	183,101	179,644	182,135	193,815	2,149,709
3		UNUC.00000736.92	NEW STORAGE BUILDING	St. Lucie	Common	321.0	3/31/2015	Addition	458,150	458,150	470,650	462,550	462,550	475,050	462,550	462,550	475,050	535,350	539,017	561,517	5,814,133
4		UNUC.00000736.90	ELECTRICAL MODS COMPLETED PSL1_26	St. Lucie	1	321.0	4/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533
5		UNUC.00000736.90	MECHANICAL MODS COMPLETED PSL1_26	St. Lucie	1	321.0	4/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533
6		UNUC.00000736.90	FLOODING	St. Lucie	1	321.0	4/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546
7		UNUC.00000736.90	SEISMIC	St. Lucie	1	321.0	4/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546
8		UNUC.00000736.92	PORTABLE EQUIP	St. Lucie	Common	321.0	4/30/2015	Addition	-	-	-	-	-	-	-	-	-	-	-	4,279,718	4,279,718
9		UNUC.00000736.91	ELECTRICAL MODS COMPLETED PSL2_22	St. Lucie	2	321.0	11/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533
10		UNUC.00000736.91	MECHANICAL MODS COMPLETED PSL2_22	St. Lucie	2	321.0	11/30/2015	Addition	53,315	53,315	56,930	45,837	45,837	49,452	43,129	43,129	56,327	70,674	67,278	76,309	661,533
11		UNUC.00000736.91	FLOODING	St. Lucie	2	321.0	11/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546
12		UNUC.00000736.91	SEISMIC	St. Lucie	2	321.0	11/30/2015	Addition	27,258	41,140	30,929	28,331	28,331	32,001	59,581	59,581	63,251	61,725	62,374	66,045	560,546
13		UNUC.00000736.92	SAFER POOLED EQUIPMENT INTANGIBLE ASSET	St. Lucie	Common	321.0	12/31/2015	Addition	422,236	14,104	22,630	15,572	12,386	7,490	12,502	7,644	21,840	14,358	7,462	6,474	564,720
14									1,594,541	1,184,695	1,202,694	1,117,636	1,114,452	1,174,554	1,228,733	1,223,875	1,341,404	1,439,588	1,429,379	5,794,756	19,845,305
15																					2,682,931 FPL Payroll
16																					17,163,374 Net of payroll

130001 Hearing Exhibits - 00239

Project : PSL - Fukushima Project

Data Supplied By : Michael McCabe

Phone Number : 772-429-7832 Date : 08/05/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Description	Plant Location	Unit Number	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1		UNUC.00000736.90	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	1	322.0	8/30/2014	Addition	152,532	123,911	135,591	128,023	128,023	139,702	128,023	128,023	139,702	136,245	136,737	150,416	1,628,927
2		UNUC.00000736.91	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	2	322.0	12/31/2014	Addition	152,532	123,911	135,591	128,023	128,023	139,702	128,023	128,023	139,702	136,245	136,737	150,416	1,628,927
3		UNUC.00000736.82	NEW STORAGE BUILDING	St. Lucie	Common	321.0	3/31/2015	Addition	424,900	424,900	437,400	429,300	429,300	441,800	429,300	429,300	441,800	503,100	505,767	518,267	5,415,133
4		UNUC.00000736.90	ELECTRICAL MODS COMPLETED PSL1_25	St. Lucie	1	324.0	4/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
5		UNUC.00000736.90	MECHANICAL MODS COMPLETED PSL1_26	St. Lucie	1	322.0	4/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
6		UNUC.00000736.90	FLOODING	St. Lucie	1	321.0	4/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
7		UNUC.00000736.90	SEISMIC	St. Lucie	1	321.0	4/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
8		UNUC.00000736.92	PORTABLE EQUIP	St. Lucie	Common	325.0	4/30/2015	Addition	-	-	-	-	-	-	-	-	-	-	-	4,279,718	4,279,718
9		UNUC.00000736.91	ELECTRICAL MODS COMPLETED PSL2_22	St. Lucie	2	324.0	11/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
10		UNUC.00000736.91	MECHANICAL MODS COMPLETED PSL2_22	St. Lucie	2	324.0	11/30/2015	Addition	34,784	34,784	38,398	28,306	28,306	31,921	25,598	25,598	38,796	53,142	49,747	58,778	448,155
11		UNUC.00000736.91	FLOODING	St. Lucie	2	322.0	11/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
12		UNUC.00000736.91	SEISMIC	St. Lucie	2	321.0	11/30/2015	Addition	19,157	33,039	22,828	20,229	20,229	23,900	51,479	51,479	55,150	53,623	54,273	57,944	463,332
13		UNUC.00000736.92	SAFER POOLED EQUIPMENT INTANGIBLE ASSET	St. Lucie	Common	303.0	12/31/2015	Addition	422,236	14,104	22,630	15,572	12,386	7,490	12,502	7,644	21,840	14,358	7,482	6,474	564,720
14									1,367,963	968,118	976,116	895,058	891,874	961,976	1,006,155	1,001,297	1,118,826	1,217,011	1,206,801	5,572,178	17,163,374
15																					-
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130001 Hearing Exhibits - 00240

Project : PSL - Fukushima Project

Data Supplied By : Michael McCabe

Phone Number : 772-429-7932 Date : 08/05/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Description	Plant Location	Unit Number	Payroll	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1		UNUC.00000736.90	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	1	FPL	321.0	8/30/2014	Addition	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	520,782
2		UNUC.00000736.91	SPENT FUEL POOL INSTRUMENTATION	St. Lucie	2	FPL	321.0	12/31/2014	Addition	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	43,399	520,782
3		UNUC.00000736.92	NEW STORAGE BUILDING	St. Lucie	Common	FPL	321.0	3/31/2015	Addition	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	33,250	399,000
4		UNUC.00000736.90	ELECTRICAL MODS COMPLETED PSL1_26	St. Lucie	1	FPL	321.0	4/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
5		UNUC.00000736.90	MECHANICAL MODS COMPLETED PSL1_25	St. Lucie	1	FPL	321.0	4/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
6		UNUC.00000736.90	FLOODING	St. Lucie	1	FPL	321.0	4/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
7		UNUC.00000736.90	SEISMIC	St. Lucie	1	FPL	321.0	4/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
8		UNUC.00000736.91	ELECTRICAL MODS COMPLETED PSL2_22	St. Lucie	2	FPL	321.0	11/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
9		UNUC.00000736.91	MECHANICAL MODS COMPLETED PSL2_22	St. Lucie	2	FPL	321.0	11/30/2015	Addition	18,531	18,531	18,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	17,531	213,378
10		UNUC.00000736.91	FLOODING	St. Lucie	2	FPL	321.0	11/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
11		UNUC.00000736.91	SEISMIC	St. Lucie	2	FPL	321.0	11/30/2015	Addition	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	8,101	97,214
										226,578	226,578	226,578	222,578	222,578	222,578	222,578	222,578	222,578	222,578	222,578	222,578	2,682,931

130001 Hearing Exhibits - 00241

Project : Fukushima

Data Supplied By : Christine Randell

Phone Number : 305-246-7343 Date : 09/02/13

Line No	Project No	Work Order (If Known) or Other Identifier (e.g. BI No.)	Plant Location	Unit Number	Four Digit Plant Account	In-Service Date	Type of Transaction	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Total For 2014
1	Flood	UNUC.00000742.02.01	Turkey Point	Common	321.0	Sep-16	Addition	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,072	241,400
2	Seismic	UNUC.00000742.03.01	Turkey Point	Common	321.0	Jun-16	Addition	5,226	5,226	5,238	72,420	72,420	72,420	72,420	72,420	72,420	0	0	0	450,211
3	Flex	UNUC.00000742.04.01	Turkey Point	Common	322.0	Sep-16	Addition	584,510	584,510	584,510	513,780	513,780	513,780	840,342	840,342	840,342	759,875	759,875	759,875	8,095,521
5	Spent Fuel	UNUC.00000742.05.01	Turkey Point	Common	322.0	Jun-16	Addition	42,969	42,969	42,969	42,969	42,969	42,969	222,088	222,088	222,088	222,088	222,088	222,088	1,590,343
6																				0
7																				0
8																				0
9																				0
10																				0

costs														
flooding	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,670	16,630	200,000	
seismic	4,330	4,330	4,340	60,000	60,000	60,000	60,000	60,000	60,000	0	0	0	373,000	
flex	588,600	588,600	588,600	530,000	530,000	530,000	815,029	815,029	815,029	748,382	748,382	748,382	8,045,972	
sfp	35,000	35,000	35,000	35,000	35,000	35,000	175,000	175,000	175,000	175,000	175,000	175,000	1,260,000	
													9,878,972	
allocations														
flooding	0	0	0	0	0	0	0	0	0	0	0	0	0	
seismic	0	0	0	0	0	0	0	0	0	0	0	0	0	
flex	10,000	10,000	10,000	10,000	10,000	10,000	15,000	15,000	15,000	15,000	15,000	15,000	160,000	
sfp	600	600	600	600	600	600	9,000	9,000	9,000	9,000	9,000	9,000	57,600	
													207,600	
contingency														
flooding	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,451	3,442	41,400	
seismic	896	896	898	12,420	12,420	12,420	12,420	12,420	12,420	0	0	0	77,211	
flex	123,910	123,910	123,910	111,780	111,780	111,780	171,816	171,816	171,816	158,016	158,016	158,016	1,696,566	
sfp	7,369	7,369	7,369	7,369	7,369	7,369	38,088	38,088	38,088	38,088	38,088	38,088	272,743	
													2,087,920	
total														
flooding	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,121	20,072	241,400	
seismic	5,226	5,226	5,238	72,420	72,420	72,420	72,420	72,420	72,420	0	0	0	450,211	
flex	722,510	722,510	722,510	651,780	651,780	651,780	1,001,845	1,001,845	1,001,845	921,378	921,378	921,378	9,892,538	
sfp	42,969	42,969	42,969	42,969	42,969	42,969	222,088	222,088	222,088	222,088	222,088	222,088	1,590,343	
													12,174,492	
Flex payroll $														
mech eng	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	420,000	
mech impl	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000	
elec eng	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	16,000	
bldg eng	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333	40,000	
bldg impl	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	200,000	
wells eng	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	180,000	
wells impl	0	0	0	0	0	0	16,667	16,667	16,667	16,667	16,667	16,667	100,000	
RCP seals eng	0	0	0	0	0	0	6,836	6,836	6,836	6,836	6,836	6,836	41,017	
overall support	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	600,000	
	138,000	138,000	138,000	138,000	138,000	138,000	161,503	161,503	161,503	161,503	161,503	161,503	1,797,017	

130001 Hearing Exhibits - 00242

Author: JKC/HWV Status of Data: 01/31/2012 10:31:52

Chart | Print | Information

Resp. cost cntr		WBS Reporting WBS		WBS Project type	Time Fiscal year/period	VE WV1 -Working Version JAN 2013 to DEC 2013 January 2013	February 2013	March 2013	April 2013	May 2013	June 2013	July 2013	August 2013	September 2013	October 2013	November 2013	December 2013	Overall Result	
[illegible]	Multiple Divisions	UNUC.0000073[illegible]	POS[illegible]HM PABC	C	Capital WBS Element			$ 24,934.49	$ 7,990.81	$ 16,267.76	$ 6,249.51		$ 1,453,352.28	$ 1,615,112.28	$ 1,615,112.28	$ 1,613,846.55	$ 1,668,694.34	$ 8,633,360.24	
		UNUC.0000074[illegible]	PTN Post Japan rebuild (Capital)	C	Capital WBS Element						$ (190.65)	$ 179,817.80	$ 186,190.08	$ 982,067.50	$ 345,867.00	$ 432,868.14	$ 2,564,218.49	$ 4,686,636.32	
		UNUC.0000073[illegible]	PSL Fukushima Flooding Walkdown/Eval	D	Deferred	$ (95,874.36)	$ 85,407.17	$ 89,421.97	$ 21,248.83	$ 209,594.45	$ 359,583.35						$ (1,223,671.34)	$ (22,441.21)	
		UNUC.0000073[illegible]	PSL Fukushima Seismic Walkdown/Eval	D	Deferred	$ 3,292.85	$ 7,876.99	$ 1,291.31			$ 4,519.59							$ 16,980.74	
		UNUC.0000073[illegible]	PSL Fukushima FLEX Strategies	D	Deferred						$ 5,480.47							$ 5,480.47	$ 0.00 Deferred
		UNUC.0000074[illegible]	PTN Fukushima Flooding Walkdown/Eval	D	Deferred	$ 6,478.07	$ 285,738.68	$ 35,091.80	$ 1,617.90								$ (308,826.45)	$ 0.00	
		UNUC.0000074[illegible]	PTN Fukushima Seismic Walkdown/Eval	D	Deferred	$ 293.51	$ 140.27	$ 198.40	$ 3,182.03								$ (3,734.21)	$ 0.00	
		UNUC.0000074[illegible]	PTN Fukushima Flex Mitigation Strategies	D	Deferred	$ 165,934.95	$ 125,567.64	$ 74,899.00	$ 76,445.31	$ 152,317.95	$ 161,764.87						$ (759,929.65)	$ 0.00	
		UNUC.0000074[illegible]	PTN Fukushima Spent Fuel Pit Instruments	D	Deferred		$ 4,898.60	$ 19,222.74	$ 15,068.42	$ 6,254.51	$ 680.56						$ (46,035.57)	$ 0.00	
		UNUC.0000074[illegible]	PSL Post Japan Interfac	E	Expense WBS Element	$ 24,352.11	$ 27,558.88	$ (7,957.41)	$ 13,487.29	$ 20,147.58	$ 17,410.82	$ 5,031.14						$ 100,009.45	
		UNUC.0000074[illegible]	Post Japan Interfac	E	Expense WBS Element	$ 12,828.46	$ [illegible]	$ (17,258.58)	$ 14,813.74)	$ 15,502.35	$ 86,681.76)	$ 9,373.00	$ 8,873.00	$ 58,873.00	$ 8,873.00	$ 8,873.00	$ (44,471.00)	$ 126,869.93	
		Result				$ 836,966.50	$ 676,350.85	$ 219,803.71	$ 137,215.55	$ 420,094.81	$ 507,958.72	$ 194,321.94	$ 1,648,415.32	$ 2,656,052.78	$ 1,964,852.28	$ 2,428,387.69	$ 1,987,448.21	$ 13,445,805.94	
						$ 0.00	$ 0.00	$ 24,934.49	$ 7,990.81	$ 16,267.76	$ 6,558.82	$ 179,817.80	$ 1,639,542.32	$ 2,597,179.76	$ 1,955,779.28	$ 2,416,514.69	$ 4,374,110.83	$ 13,218,805.56	Estimated 2013 Capital
																		$ (10,000,000)	Rate Case Forecast
																		$ 3,218,805.56	Estimated Incremental Capital
						$ 37,178.58	$ 185,820.10	$ (26,256.00)	$ 8,983.86	$ 35,848.81	$ (71,470.89)	$ 14,404.14	$ 8,873.00	$ 58,873.00	$ 8,873.00	$ 8,873.00	$ (44,471.00)	$ 227,000.39	Estimated 2013 O&M
																		$ (144,000.00)	Test Year O&M
																		$ 83,000.39	Estimated Incremental O&M

130001 Hearing Exhibits - 00243

Budget Variance Report(A/Fc/PYA)

Author JKC0HWV Status of Data 01/31/2012 10:31:52

Chart | Filter | Information

Table

Resp. cost cntr		WBS:Project type		WBS-Reporting WBS		YTD Current App Bgt Edit JAN 2013 to DEC 2013
20105	Nuclear Division	C	Capital WBS Element	UNUC.00000736.01.01	POST FUKUSHUMI DAIIC	$ 8,532,754.11
				UNUC.00000742.01.01	PTN Post Japan Initiative (Capital)	$ 5,501,395.20
		E	Expense WBS Element	UNUC.00000740.01.01	PSL Post Japan Initiative	$ 100,000.00
				UNUC.00000741.01.01	Post Japan Initiative	$ 72,000.00
		Result				$ 14,206,149.31

130001 Hearing Exhibits - 00244

Q.

The following interrogatories relate to the August 30, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Please provide the dollar amount of FPL budgeted 2014 plant additions for base rate recovery, (broken down by GBRA amounts and other), and for each type of clause.

A.

The 2014 budgeted gross plant additions for FPL's cost recovery clauses included in FPL's 2014 clause projection filings are reflected below. Note, these amounts do not include true-ups from prior periods.

GBRA (Riviera) - $1,275,582,925
Fuel - $0
Capacity (excluding NCRC) - $11,371,039
NCRC - $0
ECRC - $78,774,090
ECCR - $12,753,165

As a regular part of its annual financial forecasting process, FPL prepares forecasts of the specific plant additions that are eligible for recovery through GBRA or an adjustment clause. In order to meet the relevant filing deadlines, those forecasts are prepared before FPL's annual budget is completed. There is no separate forecast prepared for non-GBRA base rate plant additions, because there is no filing requirement for such a forecast. FPL's 2014 budget will not be completed until late 2013 or early 2014. Therefore, FPL is unable to provide the dollar amount of budgeted 2014 plant additions to go in-service for non-GBRA base rate recovery at this time. Please note that cost recovery for plant additions under GBRA and all of the adjustment clauses is subject to subsequent true-up once the actual capital costs for those plant additions are known (in the case of GBRA, there is an automatic true-up adjustment only if the actual costs are lower than the forecast).

Q.

The following interrogatories relate to the August 30, 2013 testimony of Terry J. Keith filed in Docket No. 130001-EI.

Please refer to FPL's response to Staffs Interrogatory No. 62. Please provide a breakdown of the amounts included in the response between capital and O&M expense costs.

A.

Refer to OPC's First Set of PODs No. 6.

Q.

Please refer to FPL's response to FPL's response to Staff's Interrogatory No. 62. Please provide a copy of the documents that support the estimate of costs for the NRC compliance related for the Fukushima events in the range of $93 million to $193 million through the end of 2016.

A.

See documents attached to this response. Documents responsive to this request are provided as Bates Nos. FCR-13-289 through FCR-13-305.

FUKUSHIMA FLEET PROGRAM - FLORIDA (PSL AND PTN) ESTIMATE
as of AUGUST 2013

SITE	BASE $ millions	RISK REGISTER WEIGHTED $ millions	CONTINGENCY HIGH RANGE $ millions	TOTAL LOW RANGE $ millions	TOTAL HIGH RANGE $ millions
ENGR.	9	3	6	9	18
MATL.	13	4	4	13	22
IMPL.	28	9	28	28	65
PSL	50	16	38	50	104
ENGR.	13	5	9	13	27
MATL.	13	5	5	13	23
IMPL.	16	6	17	16	39
PTN	43	16	30	43	89
TOTAL FLORIDA	93	32	69	93	193

NOTES

Base, Contingency and Risk Register numbers as presented to CNO on 8/8/13

Low Range includes Base cost absent Weighted Risk or Contingency

High Range established as Base, Weighted Risk and Contingency

High Range Contingency calculated as follows: engr. 50%, matl. 25%, impl. 75%

130001 Hearing Exhibits - 00248

FUKUSHIMA FLEX MOD RISK MANAGEMENT PTN

#	Origin Date	Risk Event Description	Impact Area (Cost, Schedule, Quality, Safety, Rep	Probability	Impact Rating	H/M/L	Maximum Cost Exposure ($000)	Type of Estimate	P	IR	WF	Weighted Risk Exposure ($000)	Impact Description	Mitigation Action	Status & Comments as of 8/01/13	Formal Risk Plan	Risk Manager	Risk Owner
1	05/15/13	New major project with fixed end dates	Cost	Near Certainty	Very High	M	$3,000	OOM	1.00	0.80	0.8	$2,400	Project has fixed compliance dates in 2015. Potential exists for fastracking areas of the project.	Develop Project implementation schedule	Currently developing design plans 12/30/13 - Reduced to $3M max exposure based on More defined individual risks	N	Jenkins	Chaviano
2	05/15/13	PTN 3 and 4 Contingency - Provide mechanical connections to plant equipment .	Cost	Likely	Budgetary	M	1,000	OOM	0.80	0.20	0.16	$160	Designs are conceptual and PTN submittal has not yet been reviewed by NRC	Complete engineering evaluation by 12/30/13	Design development working on track for 12/30/13	N	Jenkins	Chaviano
3	05/15/13	Potable water wells requires additional subitials to DERM, Miami Dade and FDEP potential impact to overall implementitions schedule	Cost	Likely	Budgetary	[redacted]	2,000	OOM	0.80	0.40	0.32	$640	The location of well has not been determined. Location of pump has significant potential to increase engineering, implementation cost and miligation strategies.	Complete engineering evaluation by 11/30/13 and determine well location.	Working	N	Jenkins	Chaviano
4	05/15/13	PTN electrical modifications to provide temporary power to 4kV bus and 480v Load Centers	Cost	Likely	Budgetary	M	1,600	OOM	0.80	0.80	0.64	$960	Design is conceptual and location of temporary generators is concern due to the actual location of PTN 480V load centers in relation to where temp generators staging locations	Complete design by 12/30/13	Working	N	Jenkins	Chaviano
5	05/16/13	Staffing analysis for actions	Cost	Likely	Budgetary	M	3,000	OOM	0.80	0.80	0.4	$1,280	Evaluation of the required mitigating actions may require additional staffing not bounded by current plant staffing.	Bring existing procedures up to date	No change	N	Jenkins	Chaviano
6	06/03/13	Communication upgrades to existing communication sytems and structures	Cost	Likely	Budgetary	M	250	OOM	0.80	0.80	0.1	$25	Final design not complete involves hardening commercial structures such as NAB com room. Floor elevation is at flood plane.	complete evaluation and design by 12/30/13	working	N	Jenkins	Chaviano

FUKUSHIMA FLEX MOD RISK MANAGEMENT

#	Origin Date	Risk Event Description	Impact Area (Cost, Schedule, Quality, Safety, HR)	Probability	Impact Rating	H/M/L	Maximum Cost Exposure ($000)	Type of Estimate	P	IR	WF	Weighted Risk Exposure ($000)	Impact Description	Mitigation Action	Status & Comments as of 8/01/13	Formal Risk Plan	Risk Manager	Risk Owner
8	06/06/13	Procedures and program development	Cost	Near Certainty	Budgetary		$2,000	OOM	1.00	1.00	0.4	$800	Existing SAMG/EOP procedures do not meet current WOG standards. Significant work required to update and include Fukushima strategies. Resource currently not available to accomplish task	Revise existing procedures to meet WOG standards. Need dedicated procedure writer.	No Change		Jenkins	Chaviano
10	06/13/13	Impact of Flooding / Hazard assessment to Building Design	Cost	Unlikely	Moderate	M	$250	OOM	0.50	0.20	0.1	$25	Changes to building design resulting from analysis	None; Change in assessment would most likely add a few more feet in Backfill, not a significant cost	No change	N	Jenkins	Chaviano
11	06/13/13	Impact of NRC RAI's	Cost	Very Likely	Very High	M	$2,000	OOM	0.80	0.80	0.8	$1,600	The amount and impact of RAI's is not known	Monitor fleet and industry OE, Partially covered by Staffing plan assumes we can handle most RFI's in house.	No change	N	Jenkins	Chaviano
12	06/13/13	Seismic Analysis	Cost	Near Certainty	Very High	M	$1,000	OOM	1.00	1.00	0.8	$800	All plants must develop new seismic hazard curves and ground motion response spectra (GMRS) and compare the new GMRS to their existing Safe Shutdown Earthquake (SSE). Plants with a revised GMRS that exceeds their SSE must perform new seismic risk evaluations.	Preliminary estimates indicate a cost of ~ $350K per site if an interim augmented approach seismic evaluation is required.	It is anticipated that the Florida plants will screen out with no further action required.	N	Jenkins	Chaviano
13	05/16/13	SFP level indication design is not complete and location for indication not identified	Cost	Likely	Budgetary	M	1,000	OOM	0.80	0.20	0.16	$160	Designs are conceptual. Routing of conduit to control room and or computer room requires tornado missile protection potential dramatic cost increase.	Develop design to minimize routing of conduit outdoors and locate display closer to SFP	working	N	Jenkins	Chaviano
14	07/10/13	RRC Staging areas - Preparation	Cost	Unlikely	High	M	$250	OOM	0.50	0.40	0.2	$50	Areas designated for RRC equipment staging may require preparation from implementation group.	Complete evaluation by 8/30/13	No change	N	Jenkins	Chaviano
15	07/10/13	Site specific training for fukushima response	Cost	Very Likely	Very High	M	$250	OOM	0.80	0.80	0.72	$180	Special training will most likely be required for ERO teams, Security, Ops, HD & Others.	Incorporate Training and Procedure development into Site Project cash flow	No change	N	Jenkins	Chaviano
16	07/10/13	FLEX Building	Cost	Highly Unlikely	Very High	M	$250	OOM	0.20	0.80	0.16	$40	FLEX building is becoming critical with respect to fleet and date and Planet Forward estimates are higher than FPL	Complete alternative analysis and make decision on building type and location	Working	N	Jenkins	Chaviano
17	06/05/13	Replace RCP seals	Cost	Near Certainty	Budgetary		3,000	OOM	1.00	1.00	1	$3,000	Replacement of RCP seals creates potential for extension of outage schedule. Potential need for additional mods with discovery with as found configuration with seal water piping.	Complete engineering evaluation by 8/26/13	Working	N	Jenkins	Chaviano
18	06/07/13	Outage Schedule for RCP Seal Replacement	Cost	Very Likely	Budgetary		2,500	OOM	1.00	0.80	0.8	$2,000	Strategy requires replacement of seals in all RCP during one outage. Significant challenge to work 3 pumps in parallel due to space restrictions in respective Containment Building. Significant potential to overall outage schedule	Develop Project implementation strategy to mitigate impact.	No Change	N	Jenkins	Chaviano
19	06/07/13	New RCP Seal Failure	Cost	Likely	Budgetary		2,500	OOM	1.00	0.80	0.8	$2,000	Seal design has never been deployed at PTN. Failure of seal during unit start up is possible requiring extended outage for potenta additional seal replacement.	Develop Project implementation strategy to mitigate impact.	No change	N	Jenkins	Chaviano
21	08/01/13	Containment Venting	Cost	Highly Unlikely	High	M	$500	OOM	0.20	0.40	0.08	$40	Potential for NRC to not accept our position and require additional venting capabilities	Monitor NRC Responses / RFI's	No change	N	Jenkins	Chaviano
###																		
		Cost Exposure					26,250					$16,380						

Keys for Calculations		(P)	(IR)				
		Near Certainty	Very Low				1.00	0.05
		Very Likely	Low				0.80	0.10
		Likely	Moderate				0.80	0.20
		Unlikely	High				0.50	0.40
		Highly Unlikely	Very High				0.20	0.80

130001 Hearing Exhibits - 00250

FCR-13-291

FUKUSHIMA FLEX MOD RISK MANAGEMENT PSL

#	Origin Date	Risk Event Description	Impact Area (Cost, Schedule, Quality, Safety, HF)	Probability	Impact Rating	H/M/L	Maximum Cost Exposure ($000)	Type of Estimate	P	IR	WF	Weighted Risk Exposure ($000)	Impact Description	Mitigation Action	Status & Comments as of 8/01/13	Formal Risk Plan	Risk Manager	Risk Owner
1	05/15/13	New major project with fixed end dates	Cost	Near Certainty	Very High	M	$8,000	OOM	1.00	0.50	0.8	$2,400	Project has fixed compliance dates in 2015. Potential adds for fastracking areas of the project.	Develop Project implementation schedule	Currently developing design plans 11/19/13 - Reduced to $3M max exposure based on More defined individual risks	N	Spike English	Dan West
2	05/15/13	PSL1 & 2 Contingency - Provide connections to facilitate local readings of essential instruments.	Cost	Very Likely	Very High	M	$1,800	OOM	0.90	0.80	0.72	$720	This plant modification would install local electrical connections to facilitate local readings of essential instruments with portable equipment. This capability is required to provide contingencies for loss of AC and DC power or damage to the instrument loop circuit. Site Engineering and Operations are currently evaluating which instruments will require local connections.	Complete engineering evaluation by 8/30/13	7-25-13 Engineering evaluation date moved to 8/30/13	N	Spike English	Dan West
4	05/15/13	U1 Condensate Storage Tank Roof Missile Shield	Cost	Unlikely	Very High	M	$2,000	OOM	0.50	0.80	0.4	$800	This plant modification would install a wind hazards missile shield on the Unit 1 CST roof. This is a contingency modification pending resolution of the U1 CST existing roof wind hazards evaluation.	Complete engineering evaluation by 8/30/13. This would be a reduction in project forecast	7-25-13 Changed to unlikely	N	Spike English	Dan West Ed Hollowell
5	05/15/13	U1&U2 Safety Injection Tank RCS Makeup	Cost	Near Certainty	Very High	M	$1,500	OOM	1.00	0.80	0.8	$1,200	This plant modification will install connections for a backup air or nitrogen supply to the SIT air operated drain valves. This backup supply would be pre-deployed during Mode 5&6 when steam generators are unavailable. This would provide a capability to open the valves and provide RCS makeup from the SITs within 1 hour if the Refueling Water Tanks are damaged by tornado missiles. This is a contingency modification pending resolution of the RWT wind hazards evaluations.	Complete engineering evaluation by 8/16/13	7-11-13 Site engr'g recommends NPE start developing Scoping Doc. 7-18-13 Sponser ok to proceed 8-01-13 moved due date	N	Spike English	Dan West
6	05/15/13	U1&U2 Boron Batching & Blending Capability	Cost	Near Certainty	Very High	M	$1,500	OOM	1.00	0.80	0.8	$1,200	This plant modification would provide electric power and compressed air to restore boron blending and batching capability within ~8 hours if the Refueling Water Tanks are damaged by tornado missiles. This is a contingency modification pending resolution of the RWT wind hazards evaluations	Complete engineering evaluation by 8/16/13	7-11-13 Site engr'g recomends NPE start developing Scoping Doc. 7-18-13 Sponser ok to proceed 8-01-13 moved due date	N	Spike English	Dan West
7	05/15/13	Flooding / Hazard assessment	Cost	Very Likely	Very High	M	$1,000	OOM	0.90	0.80	0.72	$720	New scope (site Mods) resulting from analysis. Not included in staffing plans	West, Dan: The flooding hazards reevaluation will not be complete until 2014.	On track	N	Spike English	Dan West
8	05/16/13	U1&U2 Hurricane Pre-Deployment Shelters	Cost	Unlikely	Very High	M	$1,500	OOM	0.50	0.80	0.4	$600	This plant modification would install flooding and high wind hazards qualified shelters for pre-deployment of selected FLEX portable equipment prior to a hurricane. The shelters will be required if the Flooding Hazards Reevaluation (on-going) determines that the hurricane surge water level or high winds could prevent FLEX portable equipment deployment for a period of time longer than the maximum time allowed for deployment by the FLEX mitigation strategies. The portable equipment that might require pre-deployment are the FLEX 480 VAC generators, FLEX SFP Pumps, and the FLEX S/G Pumps.	West, Dan: The flooding hazards reevaluation will not be complete until 2014.	7-11-13 Dan to expidite decision 7-18-13 Placed on hold for analysis, reduced to likely	N	Spike English	Dan West

130001 Hearing Exhibits - 00251

FCR-13-292

#	Origin Date	Risk Event Description	Impact Area (Cost, Schedule, Quality, Safety, FP)	Probability	Impact Rating	H/M/L	Maximum Cost Exposure ($000)	Type of Estimate	P	IR	WF	Weighted Risk Exposure ($000)	Impact Description	Mitigation Action	Status & Comments as of 8/01/13	Formal Risk Plan	Risk Manager	Risk Owner
9	06/03/13	U1&U2 Control Room Ventilation DC Fan	Cost	Unlikely	Moderate	M	$1,000	OOM	0.50	0.20	0.1	$100	This plant modification would install local Safety Related Battery power receptacles near the Control Room exterior doors. This would provide the capability to quickly deploy a portable DC fan to immediately initiate Control Room forced ventilation to limit the temperature excursion during a Station Blackout. This may be required pending Engineering review of the Control Room habitability analysis.	Complete engineering evaluation - currently low priority	7-11-13 on hold for priority	N	Spike English	Dan West
11	06/13/13	Impact of Flooding / Hazard assessment to Building Design	Cost	Unlikely	Moderate	M	$250	OOM	0.50	0.20	0.1	$25	Changes to building design resulting from analysis	None: Change in assessment would most likely add a few more feet in Backfill, not a significant cost	No change	N	Spike English	Dan West
12	06/13/13	Impact of NRC RAI's	Cost	Very Likely	Very High	M	$800	OOM	0.80	0.80	0.64	$512	The amount and impact of RAI's is not known	Monitor fleet and industry OE, Partially covered by Staffing plan assumes we can handle most RFI's in house.	No change	N	Dan West	Bladek
13	06/13/13	Seismic analysis	Cost	Near Certainty	Very High	M	$450	OOM	1.00	0.80	0.8	$360	All plants must develop new seismic hazard curves and ground motion response spectra (GMRS) and compare the new GMRS to their existing Safe Shutdown Earthquake (SSE). Plants with a revised GMRS that exceeds their SSE must perform new seismic risk evaluations.	Preliminary estimates indicate a cost of ~ $350K per site if an interim augmented approach seismic evaluation is required.	It is anticipated that the Florida plants will screen out with no further action required.	N	Dan West	Hollowell
14	06/13/13	Time Validation studies	Cost	Likely	Very High	M	$500	OOM	0.80	0.80	0.64	$320	Time validation studies may result in more complex or more electrical quantity installations	Continue to monitor progress of time studies	Not started	N	Dan West	Bladek
15	06/27/13	Loss of power to vital doors and HP equipment	Cost	Highly Unlikely	Moderate	M	$250	OOM	0.20	0.20	0.04	$10	Loss of power to vital doors / HP equipment may impact response capabilities.	Provide response by 8/16/13		N	Dan West	Bladek
17	07/10/13	RRC Staging areas - Preparation	Cost	Unlikely	High	M	$250	OOM	0.50	0.40	0.2	$50	Areas designated for RRC equipment staging may require preparation from implementation group.	Complete evaluation by 8/30/13		N	Dan West	Frank Baker
18	07/10/13	Site specific training for fukushima response	Cost	Very Likely	Very High	M	$250	OOM	0.90	0.80	0.72	$180	Special training will most likely be required for ERO teams, Security, Ops, HO & Others.	Incorporate Training and Procedure development into Site Project cash flow		N	Dan West	Bladek
19	07/10/13	FLEX Building	Cost	Highly Unlikely	Very High	M	$250	OOM	0.20	0.80	0.16	$40	FLEX building is becoming critical with respect to fixed end date and Planet Forward estimates are higher than FPL			N	Spike English	Chapman
21	07/15/13	Hose Cabinets or misc permanent storage.	Cost	Very Likely	Very High	M	$500	OOM	0.90	0.80	0.72	$360	Procure and install storage cabintes/racks for new flex response appurtenances. May be required but is not included in NPE scope or project forecast.	Develop new EC if required	7-18-13 Site Engingering to determine if to be included in their scope	N	Dan West	Mckenzie
22	06/01/13	Storage of N+1 Flex Equipment	Cost	Unlikely	Very High	M	$500	OOM	0.50	0.80	0.4	$200	N+1 storage will not be included inside the new FLEX Equipment Storage building. Potential exists for not finding suitable existing facilities requiring a shelted be installed.	Maintenance Manager to find suitable existing facilities to store spare equipment		N	Dan West	Plazza
23	06/01/13	Containment Venting	Cost	Highly Unlikely	High	M	$500	OOM	0.20	0.40	0.08	$40	Potential for NRC to not accept our position and require additional venting capabilities	Monitor NRC Responses / RFI's		N	Dan West	Mckenzie
24	06/07/13	New RWT Tank	Cost	Highly Unlikely	Very High	M	$30,000	OOM	0.10	0.20	0.20	$6,000				N	Dan West	Hoffman
		Cost Exposure					47,050					$15,837						

Keys for Calculations		(P)	(IR)				
		Near Certainty	Very Low			1.00	0.05
		Very Likely	Low			0.90	0.10
		Likely	Moderate			0.80	0.20
		Unlikely	High			0.50	0.40
		Highly Unlikely	Very High			0.20	0.80

130001 Hearing Exhibits - 00252

FCR-13-293

St Lucie Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 2.1 and 2.3: Seismic Design Basis	Seismic Related Miscellaneous Expenses		$29,000	$50,000 $29,000	$50,000	$50,000						$208,000
	Perform Seismic Margin Walkdown		$118,000									$118,000
	GMRS comparison & ESP Evaluation			$8,000	$350,000							$358,000
	ESEP and Seismic Margin Assessment Modifications (contengency)					$250,000	$250,000			$250,000	$250,000	$1,000,000
	Seismic Margins Assessment (contengency)						$500,000	$600,000	$100,000	$50,000		$1,250,000
Total Estimated Cost												$2,934,000

130001 Hearing Exhibits - 00253

St Lucie Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 2.1 and 2.3: Flooding Design Basis	Flooding related miscellaneous expenses			$25,000	$50,000	$50,000						$125,000
	Perform Flooding Margin Walkdown		$130,000									$130,000
	Perform Flooding Margin assessment			$25,000 $100,000	$93,239							$818,239
	Supplemtal Personnel for Flooding Walkdowns and assesments		$25,000 $25,000									$50,000
	Perform Integrated Assessment				$100,000	$250,000	$250,000					$600,000
	Implement any required upgrades /contengency (Water tight doors, flood barrier modifications)				$250,000	$1,000,000						$1,250,000
Total Estimated Cost												$2,973,239

130001 Hearing Exhibits - 00254

St Lucie Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12	2Q12	3Q12	4Q12	1Q13	2Q13	3Q13	4Q13	1Q14	2Q14	3Q14	4Q14	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20	Estimated Costs
Recommendation 4.2: Station Blackout Mitigation	FLEX related miscellaneous expenses							$86,620	$247,565	$175,000	$65,000	$65,000	$66,000	$567,354	$62,500	$62,500	$62,500	$63,500	$62,500	$62,500	$62,500	$62,500																$1,763,539
	Develop Mitigating Strategies to Satisfy ISG		$19,872	$45,158	$187,564	$904,416	$611,853	$56,000	$433,250	$433,250	$439,750	$439,750	$826,250	$826,250	$700,708	$574,293	$513,208	$460,793	$309,225	$9,975																	$7,544,451
	Purchase Identified Portable Equipment and Accessories		$225,000							$7,013,200				$7,013,200		$158,200	$65,500																					$3,284,400
	Design and Build Equipment Protection Structures								$78,200	$918,800	$1,080,000	$1,080,000	$1,080,000	$1,080,000	$1,080,000																								$6,396,000
	Design and Implement Coping Upgrades to meet new regulations							$58,371	$642,152	$271,844	$411,001	$97,042	$1,089,042	$1,569,361	$2,081,290	$1,777,779	$1,536,510	$1,037,304	$123,375	$61,422																			$13,087,291
	~~Procure and Install low-leakage RCP seals~~																																					$0
	Develop Procedures, Programmatic Controls and Training										$355,360	$355,360	$355,360	$355,360	$354,660	$354,660	$354,660	$354,660	$354,660																				$1,000,420
	Regional Response Center(s) capable to supply stored equipment to the sites within 24 and 72 hours after accident.					$15,000			$500,000	$200,000			$500,000	$150,000				$100,000			$100,000				$100,000			$100,000			$100,000			$100,000				$1,965,000
	Contingency												$3,000,000					$2,000,000																					$5,000,000
Total Estimated Cost																																						$40,021,100

130001 Hearing Exhibits - 00255

St Lucie Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 5.1: Reliable Hardened Vent	RCHV related miscellaneous expenses											$0
	Determine required upgrades per NRC Order ISG											$0
	Upgrade Wetwell Vent System											$0
	Upgrade Drywell Vent System											$0
	Contingency											$0
Total Estimated Cost												$0

130001 Hearing Exhibits - 00256

St Lucie Level 1 Schedule and Cost Estimates for Fukushima Response																					
NRC Recommendation	Activity	4Q11	1Q12	2Q12	3Q12	4Q12	1Q13	2Q13	3Q13	4Q13	1Q14	2Q14	3Q14	4Q14	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20	Estimated Costs
Recommendation 7.1: Spent Fuel Pool Instrumentation	SFP Instrumentation related miscellaneous expenses						$25,000				$25,000				$25,000																								$75,000
	Determine required upgrades per NRC Order tSG				$20,000					$450,000	$150,000																											$620,000
	Implement SFP Instrumentation Modification							$250,000				$3,261,236																											$3,511,236
	Contingency											$900,000																											$900,000
Total Estimated Cost																																							$5,106,236

130001 Hearing Exhibits - 00257

St Lucie Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 9.1: Addressing prolonged station blackout and multiunit events in Emergency Prep Communication	Identify staffing and communications upgrades needed to satisfy NRC RFI			$10,000 $25,000 $10,000	$410,000							$455,000
	Upgrade Communications Equipment		$20,000		$50,000							$70,000
	Implement any required EP facility upgrades				$250,000							$250,000
	Implement any required EP procedure upgrades				$50,000							$50,000
	Implement any required SAMG procedure upgrades											$0
	EP / Staffing and Communications related Training expenses											$0
Total Estimated Cost												$825,000

Site Annual Totals	Total Estimated Costs	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
	St Lucie	$1,794,100	$7,028,720	$24,077,160	$15,403,099	$1,906,497	$700,000	$200,000	$400,000	$350,000	$51,859,575
											$51,859,575

130001 Hearing Exhibits - 00258

Turkey Point Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12	2Q12	3Q12	4Q12	1Q13	2Q13	3Q13	4Q13	1Q14	2Q14	3Q14	4Q14	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20	Estimated Costs
Recommendation 2.1 and 2.3: Seismic Design Basis	Seismic Related Miscellaneous Expenses					$29,000				$29,000			$26,000			$25,000																						$133,000
	Perform Seismic Margin Walkdown					$103,000	$5,000	$5,000	$5,000	$6,000	$6,000	$5,000		$6,000																									$136,000
	GMRS comparison & ESP Evaluation									$8,000			$350,000																										$358,000
	ESEP and Seismic Margin Assessment Modifications (contengency)															$250,000				$250,000							$250,000				$250,000							$1,250,000
	Seismic Margins Assessment (contengency)																			$500,000				$500,000			$100,000				$50,000							$1,250,000
Total Estimated Cost																																						$3,127,000

130001 Hearing Exhibits - 00259

Turkey Point Level 4 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 2.1 and 2.3: Flooding Design Basis	Flooding related miscellaneous expenses			$50,000	$50,000	$25,000						$125,000
	Perform Flooding Margin Walkdown		$130,000									$130,000
	Perform Flooding Margin assessment		$17,000 $467,000	$253,313								$737,313
	Supplental Personnel for Flooding Walkdowns and assesments											$0
	Perform Integrated Assessment (Including NRC Fees)			$100,000	$250,000	$250,000						$600,000
	Implement any required upgrades /contengency (Water tight doors, flood barrier modifications)					$250,000	$1,000,000					$1,250,000
Total Estimated Cost												$2,842,313

130001 Hearing Exhibits - 00260

Turkey Point Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 4.2: Station Blackout Mitigation	FLEX related miscellaneous expenses			$50,000	$150,000	$150,000	$100,000					$500,000
	Develop Mitigating Strategies to Satisfy ISG			$275,000								$275,000
	Purchase Identified Portable Equipment and Accessories		$691,315		$1,000,000	$1,000,000						$4,691,315
	Design and Build Equipment Protection Structures			$300,000	$400,000	$3,600,000						$4,300,000
	Design and Implement Coping Upgrades to meet new regulations											$4,000,000
	Procure and install low leakage RCP seals		$25,000		$4,000,000	$8,000,000	$8,000,000	$4,000,000				$24,025,000
	Develop Procedures, Programmatic Controls and Training			$300,000	$500,000	$1,100,000						$2,100,000
	Regional Response Center(s) capable to supply stored equipment to he sites within 24 and 72 hours after accident.		$15,000	$300,000	$150,000 $500,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$1,965,000
	Contingency				$3,000,000	$3,000,000	$2,000,000					$8,000,000
Total Estimated Cost												$49,856,315

130001 Hearing Exhibits - 00261

| Turkey Point Level 1 Schedule and Cost Estimates for Fukushima Response | | |

Turkey Point Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 7.1: Spent Fuel Pool Instrumentation	SFP Instrumentation related miscellaneous expenses			$25,000	$25,000	$25,000						$75,000
	Determine required upgrades per NRC Order ISG											$0
	Implement SFP Instrumentation Modification			$20,000 $30,000	$60,000 $180,000	$3,618,000						$3,888,000
	Contingency					$852,000						$852,000
Total Estimated Cost												$4,815,000

130001 Hearing Exhibits - 00263

Turkey Point Level 1 Schedule and Cost Estimates for Fukushima Response

NRC Recommendation	Activity	4Q11	1Q12 2Q12 3Q12 4Q12	1Q13 2Q13 3Q13 4Q13	1Q14 2Q14 3Q14 4Q14	1Q15 2Q15 3Q15 4Q15	1Q16 2Q16 3Q16 4Q16	1Q17 2Q17 3Q17 4Q17	1Q18 2Q18 3Q18 4Q18	1Q19 2Q19 3Q19 4Q19	1Q20 2Q20 3Q20 4Q20	Estimated Costs
Recommendation 9.1: Addressing prolonged station blackout and multiunit events in Emergency Prep Communication	Identify staffing and communications upgrades needed to satisfy NRC RFI			$10,000 $25,000	$10,000 $25,000	$35,000 $35,000						$130,000
	Upgrade Communications Equipment		$20,000		$50,000							$70,000
	Implement any required EP facility upgrades				$50,000	$50,000	$250,000					$350,000
	Implement any required EP procedure upgrades				$50,000	$250,000						$300,000
	Implement any required SAMG procedure upgrades					$50,000						$50,000
	EP / Staffing and Communications related Training expenses											$0
Total Estimated Cost												$900,000
Site Annual Totals	Total Estimated Costs		2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
	Turkey Point		$1,336,315	$2,720,313	$11,520,000	$26,064,000	$14,000,000	$4,700,000	$450,000	$400,000	$350,000	$61,540,628
												$61,540,628
												$50,188,828

130001 Hearing Exhibits - 00264

AFFIDAVIT

STATE OF FLORIDA)

COUNTYOF MIAMI DADE)

I hereby certify that on this 14th day of OCTOBER, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Terry J. Keith, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 1 & 10 and co-sponsored the answer to interrogatory number 6 from in CITIZENS FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 1-11) in Docket No. 130001-EI, and that the responses are true and correct based on his/her personal knowledge.

Terry J. Keith

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of October, 2013.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTYOF ST. LUCIE)

I hereby certify that on this 14th day of OCTOBER, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Don Grissette, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 2, 3, 4, 5, 7, 8, 9 & 11 and co-sponsored the answer to interrogatory number 6 from in CITIZENS FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 1-11) in Docket No. 130001-EI, and that the responses are true and correct based on his/her personal knowledge.

Don Grissette

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of October, 2013.

LESLIE WHITWELL
MY COMMISSION EXPIRES
May 12, 2017
#EE 835063
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

Notary Public
State of Florida, at Large

My Commission Expires:
5-12-2017

65

DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-12)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 65
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0267-0295]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 130001-EI

Submitted for Filing: March 1, 2013

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-12)

Progress Energy Florida, Inc. ("PEF"), responds to Staff's First Set of Interrogatories to PEF (Nos. 1-12), as follows:

INTERROGATORIES

In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 through 2:

1. Please quantify and discuss all the costs and benefits under the following three scenarios. If the billing system does not have the ability to implement a particular scenario, explain why.

   (a) The January first billing cycle is set for January 1 or later each year (i.e., first billing cycle for January would not begin in December of prior year);

   (b) The effective date of new factors would be with the first billing cycle in February each year;

   (c) The effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (i.e., any December or November usage would be billed under prior factors).

Answer:

a) Progress Energy Florida (PEF) does not believe there are any benefits to this scenario. PEF's meter reading schedule and billing cycle process for each calendar year is established approximately 8 months in advance of January 1. Under PEF's current practices it is typical for the 1st and 2nd bill cycles of any month to be available to bill prior to the 1st of that month. It is not uncommon for a utility to close the billing revenue month prior to month end in order to accommodate the overall accounting month end closing procedures. A change in these practices would be a significant undertaking, would require significant time to put in place and would require significant programming, and changes to not only the meter reading and billing process as well as scheduling of service orders, determination of customer's billing cycle, scheduling routine maintenance and the month-end accounting closing process. While PEF does not have a cost estimate at this time for a change such as this, it would be significant. One scenario that PEF could implement is to set an effective date within the billing system such that no usage from November is included in January bills priced at the new rates. This scenario would result in some customers in the same effective billing month not being charged the same rates (i.e. customers in the 1st and 2nd bill cycles would be billed at the current rates for January bills and other customers in later bill cycles would be billed at the new rates for their January bills). Depending on whether the rate change is an increase or a decrease, this would result in a loss or gain of approximately 1-3 days of revenue associated with the rate change. For rate changes associated with PEF's annual clauses, these losses or gains would be trued-up in the subsequent year's clause. To illustrate the impact of this alternative scenario, if one considers the retail forecasted January 2013 sales of 2,673,803 mWhs and the difference in approved levelized fuel factors for the years of 2012 (5.175 cents per kWh) and 2013 (3.703 cents per kWh), deferral of 3 days of implementation for 2013 would amount to $3,280,000 of fuel revenues that would be deferred into 2014.

b) Progress Energy Florida (PEF) does not believe there are any benefits to this scenario. This would result in one month of revenue (or costs as the case may be) associated with the rate change being deferred in the fuel clause to the following year. For annual clauses this deferral would be addressed during the true-up process. For the 2013 fuel clause, using the mWh and rates referred to the response to 1 (a) above, this scenario would result in a deferral of $39,400,000 in revenue from 2013 to 2014. However, it must be noted that while changing the effective date of a rate change in the fuel clause (or other clauses) will simply cause a deferral to be recovered (or refunded) at a later date, a comparable change in the determination of the effective date of a base rate change will cause an unintended permanent loss of one month of the revenue increase or decrease. Using the 1st bill cycle

for February would not preclude February bills from including December usage priced at the new rates under PEF's current meter reading practices.

c) Please see the response to 1 (a) and (b) above. In order to have no November usage billed at the new rates, this could be accomplished as outlined in the alternative scenario proposed by PEF in response to 1 (a) above. Otherwise, in order to have no December usage billed at the new rates, this would result in a combination of the responses to 1 (a) and (b) above. In other words, PEF would not implement new rates until the February billing month and would set a specific effective date based on meter reading date such as February 1 to assure no December usage is billed at the new rates. This is different than using the 1st bill cycle for February as indicated in 1 (b) above.

2. Please discuss when and how customers receive notice of the new January factors.

Answer: Progress Energy Florida's practice for notification of rates changes (base rates or clauses) is to notify customers via bill insert 30 days prior to the rate change. For instance, for the typical January clause rate changes that have historically been effective with the first billing cycle for January, all customers will receive a bill insert in their December bills. Bill inserts typically include narrative of the changes including primary drivers and percent changes as well as detailed rate components for all tariff offerings that might be applicable to each customer.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Please provide data in a computerized spreadsheet format such as Excel.

3. For each type of fuel used for the power generated by the GPIF units dispatched, provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

3. For each type of fuel used for the power generated by the GPIF units dispatched, provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

Source:

From Schedule A-4 of Fuel Filings
MicroGADS
Estimate based off MicroGADs Data
Calculated Figure

MMBtu

Fuel Type		Year					
		1980	1990	2000	2010	2011	2012
	Nuclear	No Data	43,904,237	67,768,561	0	0	N/A
	Natural Gas	No Data	No Data	17,522,635	115,304,294	96,602,997	144,738,935
	Coal	No Data	No Data	136,896,530	122,876,326	109,385,876	106,599,485
	#2 Oil	No Data	No Data	978,131	369,094	330,897	337,727
	#6 Oil	No Data	No Data	43,124,840	7,604,752	0	N/A

GPIF Units

2000	2010	2011	2012
Anclote 1 and 2	Anclote 1 and 2	CR 1 - 5	Bartow CC
Bartow 3	CR 1 - 5	Hines 1 - 4	CR 4 - 5
CR 1 - 5	Hines 1 - 4	Tiger Bay	Hines 1 - 4
Tiger Bay	Tiger Bay		

MWH

Fuel Type		Year					
		1980	1990	2000	2010	2011	2012
	Nuclear	No Data	4,142,918	6,606,870	0	0	N/A
	Natural Gas	No Data	No Data	2,061,279	15,177,403	13,443,315	19,855,470
	Coal	No Data	No Data	14,426,897	12,148,312	10,808,657	10,064,768
	#2 Oil*	No Data	No Data	101,285	636	0	1,094
	#6 Oil	No Data	No Data	4,270,878	618,966	0	N/A

* #2 Oil in 2010 and 2012 was utilized for commissioning purposes solely

Anclote 1	Anclote 1	CR 1	Bartow
Anclote 2	Anclote 2	CR 2	CR 4
Bartow 3	CR 1	CR 3	CR 5
CR 1	CR 2	CR 4	Hines 1
CR 2	CR 3	CR 5	Hines 2
CR 3	CR 4	Hines 1	Hines 3
CR 4	CR 5	Hines 2	Hines 4
CR 5	Hines 1	Hines 3	
Tiger Bay	Hines 2	Hines 4	
	Hines 3	Tiger Bay	
	Hines 4		
	Tiger Bay		

Avg Annual Heat Rate (MMBtu/MWh)

Fuel Type		Year					
		1980	1990	2000	2010	2011	2012
	Nuclear	No Data	10.60	10.26	N/A	N/A	N/A
	Natural Gas	No Data	No Data	8.50	7.60	7.19	7.29
	Coal	No Data	No Data	9.49	10.11	10.12	10.59
	#2 Oil*	No Data	No Data	9.66	N/A	N/A	N/A
	#6 Oil	No Data	No Data	10.10	12.29	N/A	N/A

* Only MMBtu used for power gen used in this calculation. Oil used for commissioning, start ups and flame stabilization have been excluded.

Fuel Cost ($)

Fuel Type		Year					
		1980	1990	2000	2010	2011	2012
	Nuclear	No Data	No Data	$23,654,659	$0	$7,090	N/A
	Natural Gas	No Data	No Data	$67,910,111	$809,952,206	$617,845,165	$822,832,459
	Coal	No Data	No Data	$254,102,211	$495,410,896	$417,837,584	$407,895,600
	#2 Oil	No Data	No Data	$6,260,818	$6,845,069	$6,400,127	$7,232,940
	#6 Oil	No Data	No Data	$175,329,741	$80,886,529	$0	N/A

4. For each type of fuel used for the power generated by all units dispatched (including non-GPIF units), provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

4. For each type of fuel used for the power generated by all units dispatched (including non-GPIF units), provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

Source:

- From Schedule A-3 of Fuel Filings
- MicroGADS
- Estimate based off MicroGADs Data
- Calculated Figure

MMBtu

Fuel Type	Year	1980	1990	2000	2010	2011	2012
	Nuclear	No Data	43,904,237	67,768,561	0	0	0
	Natural Gas	No Data	2,885,280	54,885,584	186,290,367	186,092,945	189,832,950
	Coal	No Data	140,986,756	136,896,531	122,876,326	109,385,876	106,599,484
	#2 Oil	No Data	6693415	10,886,191	4,995,002	1,479,408	925,480
	#6 Oil	No Data	54704861	55,082,394	8,404,137	2,401,597	568,459

MWH

Fuel Type	Year	1980	1990	2000	2010	2011	2012
	Nuclear	No Data	4,142,918	6,606,870	0	0	0
	Natural Gas	No Data	234,812	6,086,880	23,663,716	23,569,365	23,997,245
	Coal	No Data	14,754,601	14,427,374	12,115,279	10,777,441	10,034,864
	#2 Oil	No Data	501,390	824,503	383,067	112,555	72,093
	#6 Oil	No Data	5,326,706	5,394,486	708,130	188,973	45,476

Avg Annual Heat Rate (MMBtu/MWh)

Fuel Type	Year	1980	1990	2000	2010	2011	2012
	Nuclear	No Data	10.60	10.26	N/A	N/A	N/A
	Natural Gas	No Data	12.29	9.02	7.87	7.90	7.91
	Coal	No Data	9.56	9.49	10.14	10.15	10.62
	#2 Oil	No Data	13.35	13.20	13.04	13.14	12.84
	#6 Oil	No Data	10.27	10.21	11.87	12.71	12.50

Fuel Cost ($)

Fuel Type	Year	1980	1990	2000	2010	2011	2012
	Nuclear	No Data	No Data	$23,654,659	$0	$0	$0
	Natural Gas	No Data	No Data	$237,565,411	$1,303,683,498	$1,177,106,865	$1,054,896,646
	Coal	No Data	No Data	$254,102,210	$495,410,896	$417,837,565	$407,895,600
	#2 Oil	No Data	No Data	$63,600,189	$80,167,910	$27,003,569	$18,829,066
	#6 Oil	No Data	No Data	$206,541,419	$90,219,661	$26,337,457	$6,890,407

5. Please provide the calculations of the maximum potential GPIF incentive amount allowed per 1,000 kWh jurisdictional sales for each year since the implementation of the GPIF. As part of the response, please show the maximum allowed jurisdictional GPIF incentive dollars, jurisdictional sales, and the percentage for heat rate incentive and availability incentive respectively.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

5. Please provide the calculations of the maximum potential GPIF incentive amount allowed per 1,000 kWh jurisdictional sales for each year since the implementation of the GPIF. As part of the response, please show the maximum allowed jurisdictional GPIF incentive dollars, jurisdictional sales, and the percentage for heat rate incentive and availability incentive respectively.

Source:
Annual GPIF Target Filings
Calcualted Figure

Max GPIF Dollars per 1,000 kWh sales																	
		Year															
		1980-1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Data	Max GPIF incentive Dollars	No Data	$3,555,701	$7,402,403	$7,700,337	$7,958,014	$8,218,782	$8,164,346	$8,653,524	$9,285,515	$11,074,256	$11,234,495	$13,230,670	$15,472,071	$17,063,378	$19,011,809	$19,755,160
	Jurisdictional Sales	No Data	18,974,895	33,473,038	34,817,196	36,501,685	37,116,108	38,013,952	38,193,103	39,176,586	40,148,242	40,830,224	41,591,068	40,687,467	36,359,970	36,376,481	36,913,251
	% for Heat Rate Incentive	No Data	48.45%	61.15%	48.43%	38.95%	43.14%	49.31%	45.82%	51.73%	48.00%	16.16%	55.99%	55.12%	79.07%	68.62%	64.84%
	% for Availability Incentive	No Data	51.55%	38.85%	51.57%	61.05%	56.86%	50.69%	54.18%	48.27%	52.00%	83.84%	44.01%	44.88%	20.93%	31.38%	35.16%
	Max GPIF Dollars per 1,000 kWh sales	No Data	$0.1874	$0.2211	$0.2212	$0.2180	$0.2214	$0.2148	$0.2266	$0.2370	$0.2758	$0.2752	$0.3181	$0.3803	$0.4693	$0.5226	$0.5352

130001 Hearing Exhibits - 00277

6. Please describe the various factors that could impact the efficient use of capital and over the long term, rates paid by customers. As part of the response, please provide the fuel and base rates breakdown for 1,000 kWh residential usage, the authorized ROE used to set base rates, the net energy for load, net MWh purchased power, net MWh generation, and T&D loss, for 1980, 1990, 2000, 2010, 2011, and 2012.

Answer: PEF maximizes the efficient use of its capital assets by making investments that are both prudent and reasonable. However, unforeseeable changes to the electric market, including but not limited to environmental regulation, fuel prices, and the price of purchased power can result in PEF utilizing capital assets either more or less than originally contemplated. PEF utilizes economic dispatch to make the most efficient possible use of its capital assets.

	Residential Rate, $/1000 kWh			MWh			
	Fuel	Base	ROE	Net Energy for Load[1, 3]	Purchased Power[2, 3]	Generation[2, 3]	T&D loss[2, 3, 4]
1980	16.70	46.65	14.30%	20,152,801	2,566,873	17,585,928	(1,236,239)
1990	24.66	44.33	12.60%	26,974,807	3,475,059	24,998,571	(1,185,098)
2000	20.53	49.05	12.00%	41,241,870	10,658,048	32,863,566	(2,258,817)
2010	46.11	48.58	10.50%	46,159,938	9,445,514	36,870,191	(2,946,372)
2011	44.61	48.58	10.50%	42,489,983	7,857,206	34,648,334	(2,800,396)
2012	48.60	48.58	10.50%	41,213,587	7,007,457	34,149,677	(2,671,032)

(1) 2000-2012 data from the "System Requirements" line of the December Operating Report, Page 2c "Production Statistics"
(2) 2000-2012 data From Schedule A1, Page 2.
(3) 1980 data from FERC Form 1, Page 431. 1990 data from FERC Form 1, Page 401
(4) 1980 and 1990 data from "Total Energy Losses" line of FERC Form 1, also includes unbilled
(5) Rates and ROE as of January 1 in the given year.

To see the chart above in Excel format, please see the document contained on the CD bearing Bates No. PEF-13FL-00001.

Docket 130001
Staff's First Set of Interrogatories, Question 6

	Residential Rate, $/1000 kWh			MWh			
	Fuel	Base	ROE	Net Energy for Load[1, 3]	Purchased Power[2, 3]	Generation[2, 3]	T&D loss[2, 3, 4]
1980	16.70	46.65	14.30%	20,152,801	2,566,873	17,585,928	(1,236,239)
1990	24.66	44.33	12.60%	26,974,807	3,475,059	24,998,571	(1,185,098)
2000	20.53	49.05	12.00%	41,241,870	10,658,048	32,863,566	(2,258,817)
2010	46.11	48.58	10.50%	46,159,938	9,445,514	36,870,191	(2,946,372)
2011	44.61	48.58	10.50%	42,489,983	7,857,206	34,648,334	(2,800,396)
2012	48.60	48.58	10.50%	41,213,587	7,007,457	34,149,677	(2,671,032)

(1) 2000-2012 data from the "System Requirements" line of the December Operating Report, Page 2c "Production Statistics"
(2) 2000-2012 data From Schedule A1, Page 2.
(3) 1980 data from FERC Form 1, Page 431. 1990 data from FERC Form 1, Page 401
(4) 1980 and 1990 data from "Total Energy Losses" line of FERC Form 1, also includes unbilled
(5) Rates and ROE as of January 1 in the given year.

130001 Hearing Exhibits - 00279

7. Please provide the projected GPIF heat rate target (Btus per kWh) and the projected MWh net generation of each GPIF unit for the years 2000 through 2012.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

7. Please provide the projected GPIF heat rate target (Btus per kWh) and the projected MWh net generation of each GPIF unit for the years 2000 through 2012.

Blocks are blacked out if the unit was not included in that year's GPIF

Projected GPIF Heat Rate Target (Btu/kWh)

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	10,022	10,091	10,183		10,407	10,117	10,483	10,073	10,213	10,712	11,384		
	Anclote 2	10,025	10,083	10,090	10,091	10,174	10,128	10,352	10,205	10,298	10,734	11,210		
	Bartow 1							10,942						
	Bartow 2							10,890						
	Bartow 3	10,140	10,105	10,053				10,216	10,311					
	Bartow CC													7,428
	Crystal River 1	9,851	9,831	9,750	9,742	9,731	9,921	10,296	10,195	10,279	10,235	10,449	10,708	
	Crystal River 2	9,851	9,788	9,619	9,566	9,685	9,662	10,116	9,766	9,824	9,934	10,190	10,524	
	Crystal River 3	10,357	10,247	10,283	10,327	10,308	10,298	10,259	10,304	10,321	10,314	10,298	10,297	
	Crystal River 4	9,422	9,389	9,413	9,323	9,322	9,342	9,511	9,421	9,480	9,570	10,311	10,326	9,947
	Crystal River 5	9,394	9,360	9,376	9,340	9,389	9,390	9,513	9,445	9,593	9,499	10,162	10,084	9,937
	Hines 1				7,259	7,530	7,317	7,450	7,363	7,349	7,530	7,746	7,697	7,291
	Hines 2									7,017	6,983	7,005	7,086	7,158
	Hines 3										7,153	7,234	7,310	7,167
	Hines 4											7,109	7,060	6,961
	Tiger Bay	7,590	7,190	8,267		7,964	7,903	8,006	8,024	7,973	7,731	8,055	7,975	

Projected Net MWh Generation

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	No Data	1,584,022	1,846,761		1,834,516	2,314,610	1,566,464	1,994,873	1,930,605	925,979	618,629		
	Anclote 2	No Data	1,899,624	1,858,662	No Data	1,891,312	2,250,117	1,424,422	1,825,617	1,525,869	915,334	489,910		
	Bartow 1							469,780						
	Bartow 2							508,202						
	Bartow 3	No Data	9,691,331	1,044,718				939,168	835,464					
	Bartow CC													6,467,098
	Crystal River 1	No Data	2,190,037	2,796,418	No Data	2,500,915	2,603,773	2,203,457	2,307,600	2,453,337	2,430,100	1,824,992	1,099,348	
	Crystal River 2	No Data	2,824,405	2,718,506	No Data	3,092,426	3,299,610	2,547,630	2,618,851	2,982,287	3,016,199	2,324,689	1,683,204	
	Crystal River 3	No Data	5,971,148	6,592,923	No Data	6,638,797	6,171,994	6,662,616	5,851,745	6,487,956	5,097,663	6,741,709	6,736,731	
	Crystal River 4	No Data	5,642,245	4,206,071	No Data	5,121,702	5,521,631	4,945,295	5,674,202	4,869,387	5,280,036	3,684,983	4,414,327	4,917,227
	Crystal River 5	No Data	52,109,156	5,409,862	No Data	5,485,039	5,431,511	4,796,518	5,497,259	5,428,433	3,872,999	4,946,077	4,728,063	4,824,239
	Hines 1				No Data	1,817,603	2,917,055	2,737,186	2,760,613	2,454,021	2,171,819	1,538,076	1,324,783	2,760,780
	Hines 2									1,995,215	3,164,961	2,151,590	1,992,511	2,996,938
	Hines 3										3,067,867	2,232,624	2,214,283	3,045,351
	Hines 4											2,378,083	2,528,123	3,223,305
	Tiger Bay	No Data	1,469,858	865,461		1,139,497	1,320,748	1,096,194	794,906	937,237	1,157,975	561,173	433,896	

130001 Hearing Exhibits - 00281

8. Please provide the actual heat rate performance (Btus per kWh) and the actual MWh net generation of each GPIF unit for the years 2000 through 2012.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

8. Please provide the actual heat rate performance (Btus per kWh) and the actual MWh net generation of each GPIF unit for the years 2000 through 2012.

Blocks are blacked out if the unit was not included in that year's GPIF

Actual GPIF Heat Rate (Btu/kWh)

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	10,177	10,126	10,386		10,218	10,057	10,515	10,368	10,829	12,155	12,596		
	Anclote 2	10,085	10,230	10,124	10,179	10,224	10,119	10,337	10,359	10,826	12,112	12,102		
	Bartow 1							10,963						
	Bartow 2							11,036						
	Bartow 3	10,201	10,270	10,008				10,478	10,260					
	Bartow CC													7,552
	Crystal River 1	9,840	9,815	9,725	9,965	10,041	10,204	10,444	10,183	10,259	10,197	10,605	10,970	
	Crystal River 2	9,735	9,761	9,656	9,672	9,634	9,616	10,106	9,708	9,875	9,882	10,297	10,450	
	Crystal River 3	10,333	10,268	10,288	10,249	10,261	10,295	10,315	10,278	10,311	10,319	0	0	
	Crystal River 4	9,308	9,396	9,441	9,341	9,430	9,423	9,550	9,604	9,614	10,010	9,902	9,875	10,503
	Crystal River 5	9,313	9,324	9,463	9,391	9,498	9,494	9,727	9,428	9,426	9,451	9,969	10,005	10,669
	Hines 1				7,314	7,442	7,285	7,531	7,409	7,330	7,642	7,989	7,719	7,353
	Hines 2									7,051	7,076	7,229	7,186	7,117
	Hines 3										7,264	7,321	7,412	7,297
	Hines 4											7,224	7,069	6,848
	Tiger Bay	7,695	7,138	8,313		8,352	7,911	7,686	7,772	7,733	7,437	8,015	8,193	

Actual Net MWh Generation

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	2,184,116	1,895,008	1,934,363		2,337,891	2,139,303	1,420,686	1,597,682	1,186,189	803,047	913,066		
	Anclote 2	1,914,301	2,231,369	2,200,597	2,180,280	2,149,994	2,162,857	1,519,844	1,691,610	1,271,516	791,879	974,341		
	Bartow 1							399,009						
	Bartow 2							375,012						
	Bartow 3	898,284	929,719	1,078,406				820,803	804,202					
	Bartow CC													6,858,053
	Crystal River 1	2,469,078	2,193,918	2,579,432	2,494,542	2,107,779	2,439,670	2,303,885	2,203,187	2,018,678	1,896,921	1,719,840	1,039,430	
	Crystal River 2	2,203,857	2,600,369	3,004,112	2,849,498	2,872,706	2,753,402	2,845,207	2,601,454	2,967,288	2,505,828	2,338,266	1,589,099	
	Crystal River 3	6,606,869	5,978,765	6,700,267	6,038,641	6,703,022	5,828,928	6,382,175	6,124,418	6,424,715	4,944,898	0	0	
	Crystal River 4	4,628,248	4,949,429	4,194,801	5,360,309	4,943,636	5,308,624	5,119,511	5,351,053	4,238,425	3,936,902	3,333,113	3,900,520	4,372,520
	Crystal River 5	5,214,987	4,488,537	4,687,322	5,472,620	5,224,548	5,384,438	4,746,271	5,180,307	5,036,134	2,798,173	4,757,103	4,203,538	3,188,963
	Hines 1				2,973,041	2,258,194	2,750,728	2,399,983	1,881,517	2,653,709	3,125,923	2,978,993	2,749,718	3,337,662
	Hines 2									2,521,694	2,908,663	3,332,301	2,978,710	3,374,305
	Hines 3										2,925,111	3,189,239	3,421,510	2,993,454
	Hines 4											3,445,281	3,084,326	3,293,091
	Tiger Bay	1,347,448	1,396,871	1,412,706		1,113,679	884,819	1,019,574	850,850	569,034	1,069,180	963,785	1,209,049	

9. Please provide the projected GPIF Equivalent Availability Factor (EAF) target and the MW capacity of each GPIF unit for the years 2000 through 2012.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

9. Please provide the projected GPIF Equivalent Availability Factor (EAF) target and the MW capacity of each GPIF unit for the years 2000 through 2012.

Blocks are blacked out if the unit was not included in that year's GPIF

Projected GPIF Equivalent Availability Factor (EAF) Target

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	92.36	78.81	91.71		94.43	94.72	87.67	90.02	91.62	90.47	94.31		
	Anclote 2	83.94	92.81	81.68	89.79	91.14	94.87	84.31	89.80	83.03	91.07	85.22		
	Bartow 1							85.62						
	Bartow 2							92.62						
	Bartow 3	82.84	93.92	80.12				95.46	88.38					
	Bartow CC													81.81
	Crystal River 1	90.28	76.39	86.75	90.83	81.13	92.42	92.72	84.46	92.48	88.32	86.33	85.47	
	Crystal River 2	75.25	84.16	65.14	62.57	81.26	85.71	82.06	72.99	84.16	87.29	85.46	94.40	
	Crystal River 3	93.43	85.48	96.21	88.98	97.14	90.52	97.31	86.86	96.78	74.62	97.45	97.41	
	Crystal River 4	75.65	95.44	76.48	91.57	85.22	89.58	93.22	94.10	83.52	95.04	72.43	84.15	90.50
	Crystal River 5	94.04	87.62	94.52	94.62	93.42	90.14	87.27	91.95	93.17	65.31	90.30	86.01	85.12
	Hines 1				85.80	88.27	88.98	87.63	84.77	83.48	78.91	84.39	76.23	84.31
	Hines 2									88.47	91.48	85.56	83.89	86.26
	Hines 3										89.92	87.81	87.85	79.62
	Hines 4											85.92	83.71	82.61
	Tiger Bay	79.13	78.71	80.31		87.99	91.36	88.99	86.82	77.66	80.87	78.14	81.38	

Projected MW Capacity

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	No Data	496	498		498	498	498	498	498	499	501		
	Anclote 2	No Data	495	495	No Data	495	495	495	495	507	507	510		
	Bartow 1							121						
	Bartow 2							119						
	Bartow 3	No Data	204	204				204	204					
	Bartow CC													1133
	Crystal River 1	No Data	379	379	No Data	379	379	379	379	379	372	375	375	
	Crystal River 2	No Data	498	486	No Data	486	486	486	486	491	494	494	494	
	Crystal River 3	No Data	765	765	No Data	773	769	769	769	769	780	789	789	
	Crystal River 4	No Data	729	720	No Data	720	720	720	720	722	722	702	699	712
	Crystal River 5	No Data	717	717	No Data	717	717	717	717	721	706	700	699	710
	Hines 1				No Data	482	482	482	482	463	466	462	462	462
	Hines 2									490	490	490	490	490
	Hines 3										499	488	488	488
	Hines 4											472	472	472
	Tiger Bay	No Data	207	207		207	207	207	207	203	214	205	205	

10. Please provide the actual GPIF Equivalent Availability Factor (EAF) performance and the MW capacity for each GPIF unit for the years 2000 through 2012.

Answer: Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

10. Please provide the actual GPIF Equivalent Availability Factor (EAF) performance and the MW capacity for each GPIF unit for the years 2000 through 2012.

Blocks are blacked out if the unit was not included in that year's GPIF

Actual GPIF Equivalent Availability Factor (EAF)

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	84.51	79.48	96.35		95.94	95.90	89.44	90.02	91.87	84.98	87.01		
	Anclote 2	86.72	92.69	84.33	90.14	91.81	95.85	84.94	90.72	85.27	90.99	83.26		
	Bartow 1							91.22						
	Bartow 2							93.52						
	Bartow 3	80.90	84.50	82.76				85.64	81.49					
	Bartow CC													86.37
	Crystal River 1	89.06	78.52	92.92	91.30	81.60	90.52	93.28	81.46	83.16	92.27	86.79	63.95	
	Crystal River 2	53.41	90.07	66.43	70.12	85.12	79.38	86.50	76.65	90.54	90.82	88.40	73.52	
	Crystal River 3	96.77	84.16	98.64	89.49	97.23	86.53	93.15	88.72	97.27	71.06	0.00	0.00	
	Crystal River 4	77.08	93.75	76.25	96.75	82.23	90.34	92.72	96.61	80.16	90.53	67.86	88.81	94.05
	Crystal River 5	91.17	83.93	98.51	95.48	96.59	85.23	86.43	93.47	93.08	65.32	89.00	88.23	78.40
	Hines 1				86.56	85.67	90.36	83.24	85.69	77.91	81.30	79.65	76.55	88.50
	Hines 2									84.19	91.51	84.33	84.03	93.43
	Hines 3										90.15	87.64	90.35	79.56
	Hines 4											86.71	86.42	86.60
	Tiger Bay	80.98	81.34	82.12		88.37	93.55	92.09	62.43	59.77	85.93	71.64	90.03	

Actual MW Capacity

		Year												
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	503	498	498		498	498	498	498	498	499	501		
	Anclote 2	503	495	495	495	495	495	495	495	507	507	510		
	Bartow 1							121						
	Bartow 2							119						
	Bartow 3	208	204	204				204	204					
	Bartow CC													1133
	Crystal River 1	369	379	379	379	379	379	379	379	379	372	375	375	
	Crystal River 2	464	486	486	486	486	486	486	486	491	494	494	494	
	Crystal River 3	754	765	765	769	769	769	769	769	769	780	789	789	
	Crystal River 4	697	720	720	720	720	720	720	720	721	722	702	699	712
	Crystal River 5	714	717	717	717	717	717	717	717	721	706	700	699	710
	Hines 1				482	482	482	482	482	463	466	462	462	462
	Hines 2									490	490	490	490	490
	Hines 3										499	488	488	488
	Hines 4											472	472	472
	Tiger Bay	206	207	207		207	207	207	207	203	214	205	205	

11. Please describe the improvement or decline in your company's heat rate performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

(a) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89;

(b) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1990-99;

(c) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2000-09;

(d) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2010-12;

(e) The amount of capital and O&M required and deployed for the heat rate improvement in each period;

(f) The amount of net GPIF incentive payments for the heat rate performance in each period (annual and cumulative);

(g) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1980-89;

(h) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1990-99;

(i) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2000-09;

(j) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2010-12;

(k) The alternative analysis (if any).

Answer: The improvement or decline in PEF's heat rate performance for the base load units as a group is shown in the data provided in the attached excel spreadsheet. The Commission's GPIF policy does not impact PEF's heat rate performance, because PEF maintains, dispatches, builds, and operates its generation fleet in the most reasonable and prudent manner possible given relevant facts and conditions at any given time. PEF takes this action without regard to the GPIF. PEF's actions such as planning, operation, and maintenance of the units do impact heat rate performance, but PEF does not have any details as to how any particular actions impacted the specific data provided in the attached excel spreadsheet. Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

11. Please describe the improvement or decline in your company's heat rate performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following: (a) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89; (b) 1990-99; (c) 2000-09; (d) 2010-12; (e) The amount of capital and O&M required and deployed for the heat rate improvement in each period; (f) The amount of net GPIF incentive payments for the heat rate performance in each period (annual and cumulative); (g) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1980-89; (h) 1990-99; (i) 2000-09; (j) 2010-12; (k) The alternative analysis (if any).

Blocks are blacked out if the unit was not included in that year's GPIF

Annual Rate of Improvement in Heat Rate

GPIF Units	Year	1980-89	1990-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Anclote 1	No Data	No Data	0.41%	-0.50%	2.57%		No Data	-1.57%	4.55%	-1.40%	4.44%	12.25%	3.63%	
	Anclote 2	No Data	No Data	1.53%	1.44%	-1.04%	0.55%	0.44%	-1.03%	2.16%	0.21%	4.52%	11.88%	-0.08%	
	Bartow 1	No Data	No Data							No Data					
	Bartow 2	No Data	No Data							No Data					
	Bartow 3	No Data	No Data	No Data	0.68%	-2.55%				No Data	-2.08%				
	Bartow CC	No Data	No Data												
	Crystal River 1	No Data	No Data	0.12%	-0.25%	-0.92%	2.46%	0.76%	1.62%	2.36%	-2.50%	0.74%	-0.60%	4.00%	3.44%
	Crystal River 2	No Data	No Data	0.57%	0.27%	-1.08%	0.16%	-0.39%	-0.19%	5.10%	-3.94%	1.73%	0.07%	4.20%	1.48%
	Crystal River 3	No Data	No Data	0.37%	-0.63%	0.19%	-0.38%	0.11%	0.33%	0.20%	-0.36%	0.32%	0.08%	No Data	No Data
	Crystal River 4	No Data	No Data	-1.84%	0.95%	0.48%	-1.06%	0.96%	-0.07%	1.35%	0.56%	0.11%	4.11%	-1.08%	-0.28%
	Crystal River 5	No Data	No Data	-0.25%	0.12%	1.49%	-0.76%	1.14%	-0.04%	2.45%	-3.07%	-0.02%	0.26%	5.48%	0.36%
	Hines 1	No Data	No Data				No Data	1.75%	-2.11%	3.38%	-1.62%	-1.07%	4.26%	4.54%	-3.38%
	Hines 2	No Data	No Data									No Data	0.35%	2.16%	-0.59%
	Hines 3	No Data	No Data										No Data	0.78%	1.25%
	Hines 4	No Data	No Data											No Data	-2.14%
	Tiger Bay	No Data	No Data	No Data	-7.24%	16.46%		No Data	-5.28%	-2.84%	1.12%	-0.51%	-3.82%	7.76%	2.23%
	System Average	No Data	No Data	0.13%	-0.58%	1.73%	0.16%	0.68%	-0.93%	2.08%	-1.31%	1.14%	2.88%	3.14%	0.26%
	Period Averages	No Data	No Data	0.60%											1.28%

Annual Rate of Improvement in Estimated Fuel Savings

GPIF Units	Year	1980-89	1990-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Anclote 1	No Data	No Data	-569%	100%	N/A		N/A	-100%	0%	N/A	-11%	71%	-130%	
	Anclote 2	No Data	No Data	0%	N/A	100%	N/A	100%	0%	0%	N/A	-105%	-21%	39%	
	Bartow 1	No Data	No Data							N/A					
	Bartow 2	No Data	No Data							N/A					
	Bartow 3	No Data	No Data	N/A	N/A	100%				N/A	100%				
	Bartow CC	No Data	No Data												
	Crystal River 1	No Data	No Data	0%	0%	0%	N/A	-4%	-32%	57%	100%	0%	0%	N/A	-45%
	Crystal River 2	No Data	No Data	443%	-100%	0%	N/A	100%	0%	0%	0%	0%	0%	N/A	100%
	Crystal River 3	No Data	No Data	-100%	0%	0%	N/A	-100%	0%	0%	0%	0%	0%	0%	N/A
	Crystal River 4	No Data	No Data	672%	-100%	0%	0%	N/A	-124%	100%	100%	56%	-432%	30%	16%
	Crystal River 5	No Data	No Data	N/A	-100%	N/A	100%	N/A	8%	644%	N/A	N/A	-100%	N/A	-98%
	Hines 1	No Data	No Data				N/A	N/A	-100%	N/A	-100%	0%	N/A	-128%	100%
	Hines 2	No Data	No Data									N/A	N/A	-287%	86%
	Hines 3	No Data	No Data										N/A	82%	-110%
	Hines 4	No Data	No Data											N/A	100%
	Tiger Bay	No Data	No Data	N/A	100%	0%		N/A	100%	N/A	-40%	-1%	106%	-100%	N/A
	System Average	No Data	No Data	74%	-14%	29%	50%	24%	-27%	114%	23%	-8%	-47%	-62%	19%
	Period Averages														

Annual Rate of Improvement in Fleetwide Estimated Fuel Savings

	Year	1980-89	1990-99	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	Annual ($ 000's)	No Data	No Data	-$5,435	$202	$440	-$1,094	-$1,327	-$1,572	-$3,358	-$2,674	-$3,882	-$9,209	-$8,235	-$13,775
	Rate of Change	No Data	No Data	N/A	104%	118%	-349%	-21%	-18%	-114%	20%	-45%	-137%	11%	-67%
	Period Averages	No Data	No Data	N/A	104%	-60%									

(E) Progress Energy Florida does not track O&M and capital allocations to projects specifically for heat rate improvement.

Net GPIF Incentive Payments for Heat Rate Performance

	Year	1980-89	1990-97	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	Annual	No Data	No Data	-$178,856	$14,651	$135,526	-$155,055	-$211,722	-$282,487	-$434,000	-$361,172	-$421,090	-$883,679	-$1,001,061	-$1,254,785
	Cumulative	No Data	No Data	-$164,205		-$4,869,524									

12. Please describe the improvement or decline in your company's availability performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

(a) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89;

(b) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1990-99;

(c) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2000-09;

(d) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2010-12;

(e) The amount of capital and O&M required and deployed for the improvement in each period;

(f) The amount of net GPIF incentive payments for the availability factor performance in each period (annual and cumulative);

(g) The annual average rate of change in the composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1980-89;

(h) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1990-99;

(i) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2000-09;

(j) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2010-12;

(k) The alternative analysis (if any).

Answer: The improvement or decline in PEF's availability performance for the base load units as a group is shown in the data provided in the attached excel spreadsheet. The Commission's GPIF policy does not impact PEF's availability performance, because PEF maintains, dispatches, builds, and operates its generation fleet in the most reasonable and prudent manner possible given relevant facts and conditions at any given time. PEF takes this action without regard to the GPIF. PEF's actions such as planning, operation, and maintenance of the units do impact availability performance, but PEF does not have any details as to how any particular actions impacted the specific data provided in the attached excel spreadsheet. Please see the attached CD bearing Bates No. PEF-13FL-00001. The file contained on the CD is in Excel format and responds to Questions 3 through 12.

12. Please describe the improvement or decline in your company's availability performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following: (a) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89; (b)1990-99; (c) 2000-09; (d) 2010-12; (e) The amount of capital and O&M required and deployed for the improvement in each period; (f) The amount of net GPIF incentive payments for the availability factor performance in each period (annual and cumulative); (g) The annual average rate of change in the composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1980-89; (h) 1990-99; (i) 2000-09; (j) 2010-12; (k) The alternative analysis (if any).

Blocks are blacked out if the unit was not included in that year's GPIF

Annual Rate of Improvement in Availability Factor

		Year													
		1980-89	1990-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
GPIF Units	Anclote 1	No Data	No Data	5.51%	-5.95%	21.23%		No Data	-0.04%	-6.74%	0.65%	2.06%	-7.50%	2.39%	
	Anclote 2	No Data	No Data	-5.86%	6.88%	-9.02%	6.89%	1.85%	4.40%	-11.38%	6.80%	-6.01%	6.71%	-8.50%	
	Bartow 1	No Data	No Data							No Data					
	Bartow 2	No Data	No Data							No Data					
	Bartow 3	No Data	No Data	No Data	4.45%	-2.06%				No Data	-4.84%				
	Bartow CC	No Data	No Data												
	Crystal River 1	No Data	No Data	24.96%	-11.83%	18.34%	-1.74%	-10.62%	10.93%	3.05%	-12.68%	2.09%	10.96%	-5.95%	-26.31%
	Crystal River 2	No Data	No Data	-41.23%	68.64%	-26.25%	5.55%	21.39%	-6.74%	8.97%	-11.39%	18.12%	0.32%	-2.67%	-16.83%
	Crystal River 3	No Data	No Data	14.06%	-13.03%	17.21%	-9.28%	8.65%	-11.01%	7.65%	-4.76%	9.63%	-26.95%	-100.00%	0.00%
	Crystal River 4	No Data	No Data	-18.07%	21.63%	-18.67%	26.89%	-15.01%	9.86%	2.63%	4.20%	-17.04%	12.94%	-25.03%	30.86%
	Crystal River 5	No Data	No Data	11.12%	-7.94%	17.37%	-3.08%	1.16%	-11.76%	1.41%	8.14%	-0.41%	-29.83%	36.26%	-0.87%
	Hines 1	No Data	No Data				No Data	-1.03%	5.47%	-7.88%	2.95%	-9.08%	4.35%	-2.02%	-3.89%
	Hines 2	No Data	No Data									No Data	8.70%	-7.85%	-0.35%
	Hines 3	No Data	No Data										No Data	-2.79%	3.10%
	Hines 4	No Data	No Data											No Data	-0.34%
	Tiger Bay	No Data	No Data	No Data	0.44%	0.96%		No Data	5.86%	-1.57%	-32.21%	-4.25%	43.76%	-16.63%	25.68%
	System Average	No Data	No Data	-1.36%	7.03%	2.12%	4.21%	0.91%	0.78%	-0.43%	-4.31%	-0.54%	2.35%	-12.07%	1.10%
	Period Averages	No Data	No Data	1.08%											-3.11%

Annual Rate of Improvement in Estimated Fuel Savings

		Year													
		1980-89	1990-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
GPIF Units	Anclote 1	No Data	No Data	-6722%	134%	499%		N/A	-51%	441%	-100%	52000%	-16839%	79%	
	Anclote 2	No Data	No Data	7690%	-104%	3431%	-82%	279%	-17%	-46%	-62%	-49%	-171%	-2321%	
	Bartow 1	No Data	No Data							N/A					
	Bartow 2	No Data	No Data							N/A					
	Bartow 3	No Data	No Data	N/A	-104%	181%				N/A	-785%				
	Bartow CC	No Data	No Data												
	Crystal River 1	No Data	No Data	-4182%	342%	50%	-84%	119%	-167%	430%	-609%	-110%	143%	-98%	-3270%
	Crystal River 2	No Data	No Data	-236%	263%	-82%	353%	-50%	-238%	286%	46%	16%	-6%	-91%	-379%
	Crystal River 3	No Data	No Data	109%	-260%	206%	-66%	-79%	-566%	-104%	384%	-70%	-853%	53%	2%
	Crystal River 4	No Data	No Data	358%	-244%	92%	1293%	-253%	-58%	-120%	2204%	-2327%	-33%	48%	133%
	Crystal River 5	No Data	No Data	-1682%	-1%	243%	-54%	405%	-124%	73%	1292%	-106%	122%	-3905%	196%
	Hines 1	No Data	No Data				N/A	-279%	186%	-596%	108%	-1442%	374%	-211%	103%
	Hines 2	No Data	No Data									N/A	106%	-1157%	107%
	Hines 3	No Data	No Data										N/A	-136%	489%
	Hines 4	No Data	No Data											N/A	159%
	Tiger Bay	No Data	No Data	N/A	532%	85%		N/A	236%	102%	-583%	76%	225%	-218%	168%
	System Average	No Data	No Data	-667%	62%	523%	227%	20%	-89%	52%	189%	5332%	-1693%	-723%	-229%
	Period Averages	No Data	No Data	396%											-114%

Annual Rate of Improvement in GPIF Unit Summed Estimated Fuel Savings

		Year													
		1980-89	1990-99	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	Annual ($ 000's)	No Data	No Data	$4,177	$1,635	-$4,512	$1,643	$18,590	$13,455	$6,181	-$2,827	$10,559	$19,707	-$18,383	-$17,823
	Rate of Change	No Data	No Data	N/A	-61%	-376%	136%	1032%	-28%	-54%	-146%	474%	87%	-193%	3%
	Period Averages	No Data	No Data	N/A	-61%	93%									

(E) Progress Energy Florida does not track O&M and capital allocations to projects specifically for availability factor improvement.

Net GPIF Incentive Payments for Availability Factor Performance

		Year													
		1980-89	1990-97	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	Annual	No Data	No Data	$512,745	$108,794	$130,906	$0	$130,992	$2,422,363	$966,353	-$1,185,876	$1,028,290	$3,051,612	$464,911	$578,655
	Cumulative	No Data	No Data	$621,539		$7,588,205									

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Before me, the undersigned authority, personally appeared **MATTHEW J. JONES**, who

(X) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 3 through 12 of Staff's First Set of Interrogatories to Progress Energy Florida, Inc. in Docket No. 130001-EI are true and correct to the best of his knowledge, information and belief.

Matthew J. Jones

Director, Energy Supply Analytics
Title

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

Rita G. Kale
Notary Public
State of North Carolina

My commission Expires: 6/17/17

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

Before me, the undersigned authority, personally appeared **NANCY HOLDSTEIN**, who

(✓) is personally known to me, or

( ) produced _____ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 1 and 2 of Staff's First Set of Interrogatories to Progress Energy Florida, Inc. in Docket No. 130001-EI are true and correct to the best of her knowledge, information and belief.

Nancy Holdstein

Principal Regulatory Specialist
Title

SUZANNE H. MILLER
MY COMMISSION # EE 854446
EXPIRES: March 27, 2017
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My commission Expires: 3/27/17

66

DEF's Responses to Staff's Second Set of Interrogatories (Nos. 13-23)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 66
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0296-0307]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 130001-EI

Submitted for Filing: March 6, 2013

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 13-23)

Progress Energy Florida, Inc. ("PEF"), responds to Staff's Second Set of Interrogatories to PEF (Nos. 13-23), as follows:

INTERROGATORIES

13. For each Request for Proposal (RFP) for coal issued in 2012 by Progress Energy Florida (PEF), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

Answer: PEF did not issue any RFP's for coal purchases during 2012.

14. Please describe the action taken for each bid identified in response to Interrogatory No. 13. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer: Please see PEF's response to Question 13.

15. During 2012, did PEF experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state charges by event.

Answer: During 2012, PEF did not experience any transportation constraints, but did experience demurrage charges for coal deliveries. Those demurrage charges were a result of river, Gulf barge and/or train loading or unloading delays. The general causes for the loading and \ or unloading delays include, but are not limited to, weather impacts and operational considerations. For example, the 2012 Midwest drought caused the Upper Mississippi River water levels to drop, making waterway navigation more difficult. Some barge delays were attributable to the August 2012 Hurricane Isaac that resulted in PEF's Gulf terminals declaring Force Majeure. Demurrage charges are not assigned nor categorized by event, rather attributable to general delays. For demurrage charges that PEF incurred for 2012, please see the following document.

16. For each RFP for natural gas issued in 2012 by PEF, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

Answer: Please see "Attachment A" for the natural gas RFP's issued during 2012 (RFP #FPC-LT-030712 and RFP #FPC-ST-102912). Please see "Attachment B" for the list of bids and the response summaries.

Please Note: "Attachment B" bearing Bates Numbers PEF-13FL-00010 through PEF-13FL-00020 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with PEF's Request for Confidential Classification dated March 6, 2013.

17. Please describe the action taken for each bid identified in response to Interrogatory No. 16. Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer: Please see "Attachment B" in response to Question 16. In summary, as part of PEF's on-going strategy to maintain a diverse, secure and competitively priced natural gas supply portfolio to meet its gas generation needs, PEF conducts periodic RFP's to procure natural gas supply over time. The RFP's request specific time periods and locations that represent firm gas supply receipt point locations on PEF's firm transportation agreements. As outlined in the attached summary documents, bids were evaluated and selected based on economics, location, term, and supply requirements.

18. Please state whether, in 2012, PEF participated in any capacity discussions or bid for any firm pipeline capacity during "open season. Please explain your response.

Answer: PEF engages in ongoing discussions with market participants to stay abreast of developments. With respect to discussions and bids into a pipeline "open season", PEF submitted [redacted] to monitor and evaluate potential upstream transportation opportunities.

19. Please state whether, in 2012, PEF participated in any discussions or bid for any firm gas storage capacity. Please explain your response and identify the gas storage providers.

Answer: PEF engages in ongoing discussions with various gas suppliers, pipelines and storage providers to stay abreast of developments and potential gas storage opportunities. During 2012, PEF participated in discussions with [redacted] facilities and discussed potential developments and opportunities. PEF did not enter any new storage agreements in 2012.

20. For each RFP for light oil issued in 2012 by PEF, list the bids received.

Answer: PEF issued one RFP for light oil in September 2012 for 2013 requirements. Please see "Attachment C". Please see "Attachment D" for a summary of the list of bids received and the response summary.

Please Note: "Attachment D" bearing Bates Numbers PEF-13FL-00031 through PEF-13FL-00033 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with PEF's Request for Confidential Classification dated March 6, 2013.

21. Please describe the action taken for each bid identified in response to Interrogatory No. 20? Include in your response an explanation of the evaluation process and how successful proposals were selected.

Answer: The bids were analyzed by calculating and comparing the estimated total average delivered cost per gallon by company to the respective facilities by using the applicable light oil published index prices and pricing parameters provided by each bidder. As future prices are not known, actual prices for the period October 2011 through September 2012 for the respective publication index prices were used to calculate estimated comparable annual average costs per gallon to each location for evaluation purposes. The company with the lowest estimated average cost per gallon for each location was recommended as the primary supplier. In addition, consistent with previous RFP's, PEF selected a back up supplier for each facility to provide additional reliability of fuel oil supply. Based on the analysis, PEF entered into agreements with the recommended fuel suppliers as outlined in "Attachment D".

22. Please describe PEF's process for purchasing power on a long-term contractual basis including how it solicits and communicates with suppliers and how it negotiates supply contracts and transmission arrangements.

Answer: PEF solicits long-term purchase power contracts through a competitive bidding and negotiation process. This process allows PEF to contract capacity and/or energy resources that best meet our system requirements in a least cost manner at any given time. The process for purchasing power on a long-term contractual basis can vary depending on the company's time horizon requirement. PEF maintains an ongoing open communication with interested parties or market participants that may meet our system needs and provide long-term supply resources to PEF. This open communication enables various solicitations or requests for proposals and ensures that PEF has obtained a representation of the best available supply resources to meet any defined need. After obtaining proposals, PEF would determine a short list of potential suppliers. In ranking order of the short-listed suppliers, detailed contract negotiations would begin to finalize a long-term contract with one or more of the specific short-listed suppliers that best meet PEF's requirements. Transmission arrangements would be handled under the company's Open Access Transmission Tariff requirements.

23. For each purchased power supply contract that PEF executed in 2012, describe the process that led to this contract. Include the supplier, volume, and delivered price information, as well as the transmission arrangements.

Answer: There were no purchased power supply contracts executed in 2012.

67

DEF's Responses to Staff's Third Set of Interrogatories (Nos. 24-34)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 67
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0308-0323]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 130001-EI

Submitted for Filing: March 20, 2013

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 24-34)

Progress Energy Florida, Inc. ("PEF"), responds to Staff's Third Set of Interrogatories to PEF (Nos. 24-34), as follows:

INTERROGATORIES

24. Please state whether performance improvement in availability and heat rate also increases the company's ability or opportunity to make off-system economy sales. As part of the response, please provide the MWh and dollar amounts of off-system economy sales by year for 2006 through 2012.

Answer: Performance improvement in availability and heat rate could increase the competitiveness of PEF's units in the wholesale market. However, there are many factors that determine the ability and opportunity to make off-system sales, only one of which is economic competitiveness. Those factors include, but are not limited to, the presence of demand in the market (driven by economics, load, and other utility generators' operations), capability to deliver the product (i.e. transmission access), the impact of "must-run" units for reliability purposes, and the relative competitiveness of other generators. So while better performance can increase the ability and opportunity to make off system sales, there are many other factors that impact PEF's ability to make such sales more. For the dollar amounts, please see attached CD (Excel file), Attachment A, Tab Question 24.

25. Please state whether performance degradation in availability and heat rate also increases the company's ability or opportunity to make off-system economy purchases? As part of the response, please provide the MWh and dollar amounts of off-system economy purchases by year for 2006 through 2012.

Answer: Performance degradation in availability and heat rate increases the chance that other wholesale generators will be more competitive, or less costly, than PEF's generation. In this case, PEF would analyze whether it was feasible to purchase the energy and satisfy customer load with off-system generation. However, as stated in the last question, it is not always within the PEF's ability to do so. The hypothetical energy supply must exist in the market, the energy must be deliverable, and PEF cannot curtail any "must-run" units for reliability purposes. For the dollar amounts, please see attached CD (Excel file), Attachment A, Tab Question 25.

26. Please provide the data in the following table.

Year	GPIF Total Points	GPIF Reward/ Penalty	System Fuel Cost at Target Level of Performance	System Fuel Cost at Actual Level of Performance	Fuel Savings / Costs
2006					
2007					
2008					
2009					
2010					
2011					
2012					

Answer: Please see attached CD (Excel file), Attachment A, Tab Question 26.

27. Please provide the data in the following table.

Year	Total EAF Points	EAF Reward / Penalty	System Fuel Cost at Target Level of EAF Performance	System Fuel Cost at Actual Level of EAF Performance	Fuel Savings / Costs due to EAF
2006					
2007					
2008					
2009					
2010					
2011					
2012					

Answer: Please see attached CD (Excel file), Attachment A, Tab Question 27.

28. Please provide the EFOR (Equivalent Forced Outage Rate) data for each GPIF unit by year for 2006 through 2012.

Answer: The data is listed in the charts below. For the Excel format, please see attached CD, Attachment A, Tab Question 28. The Equivalent Forced Outage Factor formula is as follows:

$$EFOF = \frac{(FOH + EFDH)}{PH} \times 100\%$$

EFOR (Equivalent Forced Outage Rate)								
		Year						
		2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	1.35%	1.88%	0.71%	1.94%	4.21%		
	Anclote 2	2.13%	0.23%	0.38%	0.31%	0.15%		
	Bartow 1	3.15%						
	Bartow 2	1.40%						
	Bartow 3	8.15%	9.42%					
	Bartow CC							1.37%
	Crystal River 1	4.19%	4.16%	14.74%	1.14%	8.63%	26.04%	
	Crystal River 2	5.81%	4.50%	2.59%	1.38%	0.72%	22.63%	
	Crystal River 3	0.33%	0.80%	2.07%	5.10%	100.00%	100.00%	
	Crystal River 4	2.87%	1.20%	3.58%	3.96%	7.78%	1.40%	1.53%
	Crystal River 5	3.51%	0.94%	4.37%	2.03%	4.59%	0.86%	1.83%
	Hines 1	5.83%	1.17%	1.19%	1.31%	7.20%	2.49%	1.04%
	Hines 2			5.69%	0.73%	1.32%	0.52%	0.01%
	Hines 3				0.63%	3.20%	0.16%	0.24%
	Hines 4					3.17%	1.26%	0.64%
	Tiger Bay	2.26%	29.80%	22.34%	4.78%	7.14%	0.16%	
	System Average	3.41%	5.41%	5.77%	2.12%	12.34%	15.55%	0.95%

FOH

		Year						
		2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	2.28	144.40	37.90	57.77	299.30		
	Anclote 2	160.88	4.37	5.70	9.08	3.17		
	Bartow 1	118.52						
	Bartow 2	65.47						
	Bartow 3	576.74	524.29					
	Bartow CC							85.36
	Crystal River 1	206.49	306.33	1162.77	60.71	654.64	2024.66	
	Crystal River 2	327.98	166.55	89.32	34.95	19.42	1951.47	
	Crystal River 3	0.00	40.20	97.53	396.70	8760.00	8760.00	
	Crystal River 4	195.85	35.60	247.63	218.70	567.58	78.07	21.46
	Crystal River 5	255.62	4.03	254.87	150.22	327.16	58.26	133.33
	Hines 1	99.65	0.00	95.85	90.56	561.44	108.43	56.04
	Hines 2			495.30	15.92	98.77	0.00	0.00
	Hines 3				43.34	259.15	2.05	0.00
	Hines 4					176.72	58.73	16.06
	Tiger Bay	198.10	2610.40	1959.20	418.57	392.68	13.63	

EFDH

		Year						
		2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	116.14	20.52	24.51	112.34	69.17		
	Anclote 2	25.41	15.44	27.65	18.42	9.95		
	Bartow 1	157.12						
	Bartow 2	56.80						
	Bartow 3	137.51	300.52					
	Bartow CC							34.78
	Crystal River 1	160.28	58.05	131.84	39.23	101.67	256.47	
	Crystal River 2	181.07	227.64	138.53	86.05	43.56	30.52	
	Crystal River 3	29.16	29.47	84.20	50.40	0.00	0.00	
	Crystal River 4	55.46	69.35	66.65	127.92	113.72	44.22	112.61
	Crystal River 5	51.81	78.67	129.11	27.38	75.34	16.88	27.83
	Hines 1	410.68	102.22	8.86	24.05	69.64	109.96	35.74
	Hines 2			4.83	48.23	16.54	45.48	0.71
	Hines 3				11.69	21.02	12.19	21.40
	Hines 4					101.04	51.39	40.22
	Tiger Bay	0.25	0.00	3.10	0.55	232.63	0.00	

PH								
		Year						
		2006	2007	2008	2009	2010	2011	2012
GPIF Units	Anclote 1	8760	8760	8784	8760	8760		
	Anclote 2	8760	8760	8784	8760	8760		
	Bartow 1	8760						
	Bartow 2	8760						
	Bartow 3	8760	8760					
	Bartow CC							8784
	Crystal River 1	8760	8760	8784	8760	8760	8760	
	Crystal River 2	8760	8760	8784	8760	8760	8760	
	Crystal River 3	8760	8760	8784	8760	8760	8760	
	Crystal River 4	8760	8760	8784	8760	8760	8760	8784
	Crystal River 5	8760	8760	8784	8760	8760	8760	8784
	Hines 1	8760	8760	8784	8760	8760	8760	8784
	Hines 2			8784	8760	8760	8760	8784
	Hines 3				8760	8760	8760	8784
	Hines 4					8760	8760	8784
	Tiger Bay	8760	8760	8784	8760	8760	8760	

29. Please describe the method of estimating the maximum fuel savings reported in PEF's GPIF projection and actual filings. As part of the response, please identify the source and reasoning for the use of the production simulation model for the actual filings.

Answer: Progress Energy Florida follows the requirements and methods detailed in the GPIF manual. PEF uses GenTrader modeling software, developed by PCI for production cost modeling and fuel savings estimation in the GPIF projection filings. PEF does not use a production cost model (GenTrader) for the True-Up (actual) filings, only for the projection (target) filings.

30. Please provide a comparison of the projected and actual monthly fuel cost for 2012 and factors contributing to the difference. As part of the response, please provide the data and calculations supporting the following:

a) Difference in average monthly heat rates for the aggregated GPIF units,

b) Difference in average monthly heat rates for the system (including non-GPIF units),

c) Difference in average monthly fuel price ($/mmBtu) for the aggregated GPIF units,

d) Difference in average monthly fuel price ($/mmBtu) for the system (including non-GPIF units),

e) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model,

f) Difference in monthly fuel cost dollars for the system (including non-GPIF units), caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model,

g) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can

be calculated and verified without the use of production simulation model, and

h) Difference in monthly fuel cost dollars for system (including non-GPIF units), caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model.

Answer: Please see the Table titled, "2012 Monthly Fuel Cost" on CD, Attachment A, Tab 30. This chart is a comparison of the projected and actual monthly fuel cost for 2012 and factors contributing to the difference.

a. Please see Table attached on CD, Attachment A, Tab 30, titled, "2012 Average Monthly Net Heat Rates".

b. Please refer to the last line of Table attached on CD, Attachment A, Tab 30, titled, "2012 Average Monthly Net Heat Rates".

c. Please see Table attached on CD, Attachment A, Tab 30, titled, "2012 Average Monthly Fuel Price ($/mmBtu)".

d. Please refer to the last line of Table attached on CD, Attachment A, Tab 30, titled, "2012 Average Monthly Fuel Price ($/mmBtu)".

e. PEF does not track or allocate fuel cost dollar differences to specific factors. However, general trends are outlined in the Tables contained on CD, Attachment A, Tab 30. Factors outside the Company's control that can cause a difference in actual fuel costs compared to estimated fuel costs include, but are not limited to, the following: spot fuel prices; an unexpected increase or decrease in load; updated fuel inventory levels (based on aerial surveys or estimates of tank bottoms); unexpected must run units; and unexpected forced outages. Regarding environmental limitations, lightning is a frequent cause of forced outage at several of PEF's facilities in the interior of PEF's territory. PEF is unaware of any manner in which a difference in fuel dollars could be calculated and verified without the use of a production simulation model.

f. Please see response to e).

g. PEF does not track or allocate fuel cost dollar differences to specific factors. However, general trends are outlined in the Tables contained on CD, Attachment A, Tab 30. PEF had no resource additions in 2012 and is not aware of any factors within its control that cause differences in the monthly fuel cost dollars. As mentioned previously, it is difficult to calculate the hypothetical system impacts, even with the use of production

modeling software. PEF is unaware of any manner in which a difference in fuel dollars could be calculated and verified without the use of a production simulation model.

h. Please see response to g).

31. Please state the manner in which the GPIF mechanism may be modified to achieve the same fuel savings and efficiency objective that will allow fuel savings to be calculated and verified without the use of production simulation model.

Answer: PEF is unaware of any manner in which the GPIF mechanism could be modified to achieve the same fuel savings and efficiency objective that will allow fuel savings to be calculated and verified without the use of a production simulation model.

32. Please state the manner in which your company sets performance expectations for individual unit production efficiency, measures performance against expectations, and calibrates incentives for management accountability for the individual plant.

Answer: Generating unit performance expectations are set during the fall of each year based on historical unit-specific data, top quartile performance for industry units of similar technology, and a forward look at expected operating conditions. These key performance indicators (KPIs) are then tracked each month with written reports issued to each generating station and the power generation management team, with the expectation that significant deviations are discussed and addressed. The KPIs tracked in this manner include equivalent forced outage rate, equivalent availability, commercial availability and heat rate. Some of these KPIs are included in annual incentive goals for all employees in the generating department. Individual contributor goals are more likely to reflect unit and station-specific expectations while manager goals are typically centered around fleet performance.

33. Describe the manner in which your company sets performance expectations for total system production efficiency, measures performance against expectations, and calibrates incentives for management accountable for the total system.

Answer: Generating unit performance expectations are set during the fall of each year based on historical unit-specific data, top quartile performance for industry units of similar technology, and a forward look at expected operating conditions. The goals are developed with data at a unit level that in turn can be rolled up to a site, region, and fleet level view. These key performance indicators (KPIs) are then tracked each month with written reports issued to each generating station and the power generation management team, with the expectation that significant deviations are discussed and addressed. The KPIs tracked in this manner include equivalent forced outage rate, equivalent availability, commercial availability and heat rate. Some of these KPIs are included in annual incentive goals for all employees in the generating department. Individual contributor goals are more likely to reflect unit and station-specific expectations while manager goals are typically centered around fleet performance.

34. Describe the manner in which your company evaluates the effectiveness of its incentive mechanism, makes improvement in the mechanism, and promotes sharing best practices that improve production efficiency?

Answer: During the fall goal-setting season, the incentives tracked are analyzed by the generation management team to determine effectiveness at achieving the expectations, with the ultimate goal being top quartile performance when compared to industry peers. The incentive structure is periodically modified to ensure the desired behavior is key to achieving the expectation. Sharing best practices is done a number of ways. The Progress Energy Florida (PEF) power generation fleet has a daily production call where events are discussed and lessons learned are shared. The PEF management team then interacts with the other geographical regions in the broader Duke Energy fleet on a second daily fleet call, assuring lessons learned from the entire Duke fleet are communicated and brought back to each region. These lessons learned include production efficiency topics. Similarly, each region of the generation department distributes a weekly report that may include lessons learned on a number of topics, including production efficiency. In addition, management at the fleet level of the power generation department regularly visit all the generating stations and receive written and verbal reports on unit and station status. Management uses these visits as an opportunity to share best practices from around the expansive Duke Energy fleet. Industry-wide best practices are gleaned from our participation in committees, conferences and groups such as AEIC and EPRI where we gauge ourselves against our utility peers and then share internally to assure continuous improvement in our operation. Production efficiency is also monitored by our Monitoring and Diagnostics (M&D) Center, a technical group located in our St Petersburg headquarters location. Using advanced diagnostics tools that include pattern recognition software, the technicians communicate with the generating sites on a daily basis concerning reliability and efficiency issues.

68

DEF's Responses to Staff's Fourth Set of Interrogatories (Nos. 35-38)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 68
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0324-0327]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 130001-EI DATED: April 29, 2013

DUKE ENERGY FLORIDA'S RESPONSE TO STAFF'S FOURTH SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA (NOS. 35-38)

Duke Energy Florida ("DEF") responds to Staff's Fourth Set of Interrogatories (Nos. 35-38) as follows:

INTERROGATORIES

35. Please refer to page 6 of the March 1, 2013 testimony of PEF witness Thomas Foster, lines 10 through 11. What is the current status of these negotiations regarding a final settlement agreement with NEIL?

Response:

The negotiations regarding a final settlement agreement with NEIL have been completed and the settlement has been finalized. DEF will credit the proceeds to customers in a manner consistent with the settlement approved by Order PSC-12-0104-FOF-EI.

36. Please refer to page 8 of the March 1, 2013 testimony of PEF witness Thomas Foster, lines 8 through 11. How did PEF calculate the fuel costs on the incremental generating units for replacement power?

Response:

DEF uses a third party electric industry standard production cost model to compare the costs for two daily cases. Both cases contain actual system loads, actual unit constraints, and market prices for fuel and emissions. One case

includes the energy delivered to CR3 Joint Owners, and the other does not. The cost difference between the two cases represents the incremental cost.

37. Please refer to pages 2 and 3 of exhibit TGF-1T, attached to the March 1, 2013 testimony of PEF witness Thomas Foster, line 12 (on both pages). Explain the regulatory accounting adjustments of $127,186 in March 2012, $13,429 in August 2012, and ($1,753,018) in December 2012.

Response:

The regulatory accounting adjustments represent the wholesale fuel deferral true-up, and the interest paid to customers on a portion of the NEIL payment returned to customers in August 2012.

Specifically, the $1,753,018 adjustment in December 2012 represents the wholesale deferral true-up for 2012, with actuals through November 2012 and an estimated amount for December 2012. The $127,186 adjustment in March 2012 represents a true-up to the December 2011 adjustment for December 2011 actuals.

The $13,429 is interest paid to customers on the $10,928,571 in NEIL Replacement Power Reimbursements paid to customers in August 2012.

38. In its 2013 actual/estimated or 2014 projected testimony, will PEF propose any new contract, new capital project, or other new cost for fuel or capacity cost recovery? If so, please list all such proposals.

Response:

None at this time.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 26th day of April, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared THOMAS G. FOSTER, who is personally known to me, and he/she acknowledged before me that he provided the answers to interrogatory number(s) 35 through 38 from STAFF'S FOURTH SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA (NOS. 35-38) in Docket No(s). 130001-EI, and that the responses are true and correct based on his personal knowledge.

(Signature)
THOMAS G. FOSTER

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of April, 2013.

SUZANNE H. MILLER
MY COMMISSION # EE 854446
EXPIRES: March 27, 2017
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida, at Large

My Commission Expires:
3/27/17

69

DEF's Responses to Staff's Fifth Set of Interrogatories (Nos. 39-40)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 69
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0328-0331]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 130001-EI DATED: May 28, 2013

DUKE ENERGY FLORIDA'S RESPONSE TO STAFF'S FIFTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA (NOS. 39-40)

Duke Energy Florida ("DEF") responds to Staff's Fifth Set of Interrogatories (Nos. 39-40) as follows:

INTERROGATORIES

Interrogatory Nos. 39-40 are in regard to the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

39. Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) tables in the actual filings for 2006 through 2012.

RESPONSE:

See document attached bearing Bates No. 13FUEL-STAFFROG5-39-000001.

40. Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the projection filings for each year during the period from 2006 through 2012. If the amounts are different from the ones contained in the actual filings, please explain.

RESPONSE:

See response to No. 39 above.

Question 39 Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) tables in the **actual** filings for 2006 through 2012.

	2006	2007	2008	2009	2010	2011	2012
Max Reward	$10,397,272	$10,064,682	$12,497,638	$15,475,873	$18,271,552	$19,027,639	$19,304,422
Savings	$95,865,141	$104,832,615	$102,814,332	$170,006,641	$69,042,368	$59,435,531	$79,804,324
Max Penalty	-$10,397,272	-$10,064,682	-$12,497,638	-$15,475,873	-$18,271,552	-$19,027,639	-$19,304,422
Loss	-$71,973,141	-$211,262,665	-$171,736,450	-$222,840,141	-$124,538,368	-$87,315,331	-$119,526,224

Question 40 Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the **projection** filings for each year during the period from 2006 through 2012. If the amounts are different from the ones contained in the actual filings, please explain.

	2006	2007	2008	2009	2010	2011	2012
Max Reward	$11,074,256	$11,234,495	$13,230,670	$15,472,071	$17,063,378	$19,011,809	$19,755,160
Savings	$95,865,141	$104,832,615	$102,814,332	$170,006,641	$71,644,082	$59,435,531	$74,307,278
Max Penalty	-$11,074,256	-$11,234,495	-$13,230,670	-$15,472,071	-$17,063,378	-$19,011,809	-$19,755,160
Loss	-$71,973,141	-$211,262,665	-$171,736,450	-$222,840,141	-$127,140,082	-$87,315,331	-$114,029,178

Differences in maximum reward/penalty:
These differences arrive from the fact that predicted end of month book value of common equity values were slightly different from the actual end of month book value of common equity values

Differences in Savings/Loss levels:
In response to Q40, the max savings/loss amounts shown for years 2010 and 2012 reflect different amounts than those shown for the same years in the Q39 table. To explain, in the 2010 and 2012 projection filings, the "Reward/Penalty Table" reflected slightly different figures than what was used in other exhibits in the same respective filings, such as the "GPIF Target and Range Summary" exhibit. Although the "Reward/Penalty Table" reflected incorrect figures for the fuel savings and fuel losses, the "GPIF Target and Range Summary" exhibit contained the correct fuel savings and fuel losses. The Company's GPIF reward/penalty was calculated for each year using the correct information. The "Reward/Penalty Table" is a cover summary sheet of the more detailed data contained in other exhibits and is not used to calculate the GPIF reward/penalty. Using the information provided in the "GPIF Target and Range Summary" exhibit results in the same maximum fuel savings and losses contained in the actual filing (i.e. for 2010 projection filing, the maximum fuel savings is $71,644,082 and the maximum loss is -$127,140,082 and for the 2012 projection filing, the maximum fuel savings is $74,307,278 and the maximum loss is -$114,029,178).

130001 Hearing Exhibits - 00330

AFFIDAVIT

STATE OF North Carolina)

COUNTY OF Mecklenburg)

I hereby certify that on this 28 day of May, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MATTHEW J. JONES, who is personally known to me, and he/she acknowledged before me that he provided the answers to interrogatory number(s) 35 through 38 from STAFF'S FIFTH SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA (NOS. 39-40) in Docket No(s). 130001-EI, and that the responses are true and correct based on his personal knowledge.

(Signature)
MATTHEW J. JONES

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28 day of May, 2013.

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

Rita G Kale
Notary Public

My Commission Expires:
6/17/2017

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70

DEF's Responses to Staff's Sixth Set of Interrogatories (Nos. 41-48)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 70
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0332-0337]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 130001-EI DATED: August 9, 2013

DUKE ENERGY FLORIDA, INC.'S RESPONSE TO STAFF'S SIXTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA (NOS. 41-48)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Sixth Set of Interrogatories (Nos. 41-48) as follows:

INTERROGATORIES

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 41-48.

41. Describe the manner in which PEF applied the formulaic representation at Original Sheet No. 3.400 where a provision limits the maximum allowed incentive dollars. As part of the response, please describe whether PEF's application of this provision, if any, has been changed by Commission orders since the inception of the GPIF, including the stipulation by Order No. 18136 in Docket No. 870001-EI.

Response:

DEF applies the limiting provision through a reasonableness review prior to submission of the GPIF target filing. DEF is not aware of any changes to this reasonableness review due to that order or any other.

42. Have the maximum allowed incentive dollars ever exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of your company's GPIF projection or actual filings in the period of 2005 through 2012? If so, please provide the year and the reasons.

Response:

No. During 2005-2012, the maximum allowed incentive dollars reached no higher than 32.01% of the maximum attainable fuel savings.

43. Describe whether the linear scale and interpolation used by PEF in its reward (penalty) tables is based on data supporting the linear relationship or the need for simplicity. If applicable, please provide data that demonstrate the relationship between the performance levels and fuel savings.

Response:

DEF has no records of analysis regarding the linear relationship. DEF has maintained this method as it is detailed in Original Sheet No. 3.401 of the GPIF Implementation Manual.

44. Based on the use of linear interpolation, should the reward (penalty) be capped at 50 percent of the fuel savings corresponding to the actual performance level in the reward (penalty) table by setting the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings? If not, please explain.

Response:

DEF believes the current GPIF process and structure have and continue to encourage utilities to efficiently operate their base load plants. However, for the reasons explained below DEF could support revising the method by which the maximum GPIF reward is calculated, whereby the new process sets the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings; the reward and penalty amounts would then be calculated as a linear interpolation from maximum allowed incentive dollars, thereby preserving the symmetrical relationship between rewards and penalties. DEF believes this revision directly ties the utility reward (penalty) to the resulting fuel savings or loss experienced by the ratepayer.

45. Should the existing minimum heat rate threshold of 75 Btu/kWh be modified, with a different number or a percentage based on the unit efficiency? As part of the response, please provide the data and analysis supporting your response.

Response:

DEF does not believe that a modification to the minimum heat rate threshold is required. The original purpose of the neutral band was to address fluctuations around the heat rate measurement due to limitations upon accuracy that are inherent in ANOHR measurement. DEF believes the existing minimum heat rate threshold continues to adequately serve this purpose.

46. Should there be a similar minimum availability performance threshold for the GPIF reward (penalty)? As part of the response, please provide the data and analysis supporting your response.

Response:

DEF does not believe a minimum availability performance threshold is appropriate. As stated in Order No. 9558, the Commission "decided to place a 'neutral band' of 75 BTU/kwh around the heat rate measurement, to reflect the limitations upon accuracy inherent in such measurements." This determination was made after varying testimony was given on this issue. The creation of the ANOHR "neutral band" was to eliminate minor heat rate fluctuations that resulted from accuracy measurement limitations and various other impacts to which the utilities have no control. The establishment of the "neutral band" helped to ensure the utilities were neither rewarded nor penalized for these limitations. DEF does not believe that a similar set of limitations exist in the availability calculations or measurements. Therefore, the establishment of a minimum performance threshold or "neutral band" for availability is unnecessary.

47. Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? As part of the response, please provide the data and analysis supporting your response.

Response:

DEF does not believe that modifications to the minimum threshold are necessary to improve the effectiveness of the GPIF. The establishment of the GPIF was to encourage utilities to efficiently operate their base load plants. DEF believes the current GPIF process and structure have and continue to achieve that goal.

48. Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? If so, provide data and analysis supporting such modification.

Response:

See response to question 47.

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBERG)

I hereby certify that on this 8th day of August, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MATTHEW J. JONES, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 41-48 from STAFF'S SIXTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA (NOS. 41-48) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Matthew J. Jones

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of August, 2013.

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

Rita G Kale
Notary Public

My Commission Expires: 6/17/2017

71

DEF's Responses to Staff's Seventh Set of Interrogatories (Nos. 49-62)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 71
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0338-0385]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Docket No. 130001-EI

Submitted for Filing: October 17, 2013

DUKE ENERGY FLORIDA'S RESPONSES TO STAFF'S SEVENTH SET OF INTERROGATORIES (NOS. 49-62)

Duke Energy Florida, Inc. ("DEF"), responds to Staff's Seventh Set of Interrogatories to DEF (Nos. 49-62), as follows:

INTERROGATORIES

49. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for natural gas, please provide the following information in a schedule format:

(a) the transaction date (the date the swap was entered into) for the swap;

(b) the fixed price for the swap;

(c) the month or period in the future the swap is covering; and

(d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

Answer: Please see Attachments bearing bates numbers PEF-13-FL-001932 through PEF-13-FL-001946.

Please Note: "Attachments bearing Bates Numbers PEF-13-FL-001932 through PEF-13-FL-001946 are confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated October 17, 2013.

50. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for fuel oil, please provide the following information:

(a) the transaction date (the date the swap was entered into) for the swap;

(b) the fixed price for the swap;

(c) the month or period in the future the swap is covering; and

(d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap. Please provide your responses in a schedule format.

Answer: Please see Attachments bearing bates numbers PEF-13-FL-001947 through PEF-13-FL-001950.

Please Note: "Attachments bearing Bates Numbers PEF-13-FL-001947 through PEF-13-FL-001950 are confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated October 17, 2013.

51. For interrogatories 49 50 above, please explain any difference between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

Answer: The trading prices represented in responses 49 and 50 are the actual prices at which DEF executed the various transactions. Consistent with prior years, the market prices used for the basis of the comparison are the closing daily settlement market prices for each individual month for the respective trade date of each transaction. DEF used the closing daily settlement market prices, as these prices were the data that was readily available. This simplified method of comparison will result in calculated pricing differences between the prices that DEF executed the various transactions versus the closing market prices on those same days. These differences are due to the timing of when DEF executed the transactions during the trading day and the closing market prices on those days for the respective periods hedged. It is common for commodity prices for the forward time periods to fluctuate, sometimes significantly, throughout a trading day. Thus, there will be differences between closing daily settlement prices for any respective month and period and the price levels that DEF executed the various trades for throughout the trading day. In addition to the timing of trade execution differences, there will also be differences that are caused by transactions that included basis in the transaction price, such as Transco ZN4, versus a NYMEX market price which does not include the basis. Additional differences result from comparing individual month closing prices to trades that were executed for multiple time periods such as common seasonal and annual strip periods where the same fixed price was executed for the entire time period. Lastly, unlike the NYMEX natural gas contract, the heavy oil market is not as liquid and the heavy oil forward curve is not as observable beyond a period of approximately 18 to 24 months.

As can be seen from the comparison utilizing the simplified comparison method, DEF had transactions where the comparison would indicate DEF traded below market and above market. However, DEF always executes transactions at the prevailing market price that exist at the time of the trade during the trading day and the highlighted differences in the Attachments are the result of differences between the market prices that existed at the time DEF executed the transactions during the course of the trading day and the closing prices used for the comparison as noted above. Additionally, some months of strip trades fell both in the test period and outside the test period which will result in additional differences when calculating percentage variances. DEF executes all of its natural gas and fuel oil transactions at the prevailing market price that exist at the time the transactions are executed during the course of the trading day.

As summarized in Question 49 and 50, DEF has outlined on the Attachments bearing bates numbers PEF-13-FL-001932 through PEF-13-FL-001946 and the Attachments bearing bates numbers PEF-13-FL-001951 and PEF-13-FL-001952 for Question 51 illustrations of this for natural gas and heavy oil trades executed for 2012 and 2013. These are further described below.

As outlined in Example #1 on the Attachment bearing bates number PEF-13-FL-001951, DEF executed a natural gas financial swap for the November 2012 through March 2013 time period on January 30, 2012 for [redacted] per MMBtu. During the course of the trading day on January 30, 2012, the market price for the November 2012 through March 2013 strip time period traded from a low of approximately $3.4728 per MMBtu to a high of approximately $3.6216 per MMBtu, a range of approximately $0.1488 per MMBtu, and closed on that day at $3.5262 per MMBtu. At the time DEF executed this trade, the market price for this time period was [redacted] per MMBtu and as illustrated above was within the daily trading range.

As outlined in Example #2 on the Attachment bearing bates number PEF-13-FL-001951, DEF executed a natural gas financial swap for the November 2012 through March 2013 time period on February 7, 2012 for [redacted] per MMBtu. During the course of the trading day on February 7, 2012, the market price for the November 2012 through March 2013 strip time period traded from a low of approximately $3.4762 per MMBtu to a high of approximately $3.6284 per MMBtu, a range of approximately $0.1522 per MMBtu, and closed on that day at $3.4786 per MMBtu. At the time DEF executed this trade, the market price for this time period was [redacted] per MMBtu and as illustrated above was within the daily trading range.

As outlined in Example #3 on the Attachment bearing bates number PEF-13-FL-001951, DEF executed a natural gas financial swap for the November 2012 through March 2013 time period on February 28, 2012 for [redacted] per MMBtu. During the course of the trading day on February 28, 2012, the market price for the November 2012 through March 2013 strip time period traded from a low of approximately $3.3690 per MMBtu to a high of approximately $3.4580 per MMBtu, a range of approximately $0.0890 per MMBtu, and closed on that day at $3.3740 per MMBtu. At the time DEF executed this trade, the market price for this time period was [redacted] per MMBtu and as illustrated above was within the daily trading range.

With respect to heavy oil transactions that appear to fall outside the 5% threshold for 2012 periods outlined in Example #4 on the Attachment bearing bates number PEF-13-FL-001952, the same explanation outlined above for strip trades applies to these trades as well. In addition, unlike the NYMEX natural gas contract, which is liquid, the New York Harbor 1.0 Residual fuel oil is not as liquid and not as

observable via transparent market beyond a period of approximately 18 to 24 months. As such, on the trade dates for the trades outlined in Example #4 on Attachment bearing bates number PEF-13-FL-001952, there was not a transparent observable forward curve for the 2012 calendar year strip trades or an intraday observable price range data available for calendar year 2012 on the trade dates. For background, for question 50 on the trade date of these transactions outlined in Example #4, the market price reported on the trade date for heavy oil was an internal estimated indicative price modeled using a relationship to the liquid observable WTI crude oil commodity. At the time of the trade, this relationship was derived by taking the ratio of the WTI Crude forward price to NYH 1.0 forward price reported by the Intercontinental Exchange (ICE) Monthly Price Validation service. This service surveys companies with interest in commodity trading and calculates a market consensus of indicative long-range forward prices for different pricing points and fuels. As part of estimating the indicative price for non-observable pricing periods, each month Enterprise Risk Management (ERM) would update the ratio and used it to convert the daily-observed WTI crude prices to NYH 1.0 prices. This methodology described was discontinued in 2009 as it was deemed to be insufficient to capture the quickly changing oil markets and the relationship between the fuels. However, this was the indicative estimated market price reported in the system on the respective trade dates as there was no observable market. Thus, on the trade dates there will be percentage variances between the traded price executed and the indicative calculated market price in the system for the respective periods. Today, changes are made to the daily forward prices of heavy oil based on the percentages changes in WTI crude on a daily basis. However, regardless of the reported internal modeled prices for the non-observable forward prices for heavy oil, DEF always pays market price for the products it hedges. DEF identified trades that based on the simplified comparison were outside of the 5%. DEF included market quotes from financial counterparties for additional transparency prior to execution of the least cost transaction at the time. With the above background, as described in example #4 an additional explanation is outlined below for heavy oil hedge trades.

As outlined in Example #4 on Attachment bearing bates number PEF-13-FL-001952, with respect to the heavy oil trade executed on December 18, 2008 for calendar year 2012 strip, DEF obtained three independent quotes from three separate companies that ranged from [redacted] per barrel to [redacted] per barrel. DEF executed the lowest market price of [redacted] per barrel which was the price at the time of the trade. Although the comparison on Question 50 would indicate what DEF paid versus the estimated indicative modeled strip price for 2012 as noted above, DEF executed the trade at the prevailing market at the time of the trade.

As all these examples illustrate, market prices for natural gas and fuel oil change within trading days and can experience large movements within any given trading day for the respective forward time periods being hedged. As noted previously, DEF always executes trades at the market prices that exist at the time trades are executed within the trading day and all the trades executed for the test period were executed at the prevailing market price that existed at the time of the trade on the respective trading day.

Please see Attachments bearing bates numbers PEF-13-FL-001951 and PEF-13-FL-001952.

Please Note: "Attachments bearing Bates Numbers PEF-13-FL-001951 and PEF-13-FL-001952 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated October 17, 2013.

52. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with options for natural gas prices, please provide the following information in a schedule format:

(a) the transaction date for the option;

(b) the option price or premium;

(c) the type of option;

(d) the time to expiration; and

(e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

Answer: Please see Attachment bearing bates number PEF-13-FL-001953 through PEF-13-FL-001955.

Please Note: "Attachments bearing Bates Numbers PEF-13-FL-001953 through PEF-13-FL-001955 is confidential and a redacted copy has been attached hereto. An unredacted copy has been filed with the Florida Public Service Commission along with DEF's Request for Confidential Classification dated October 17, 2013.

53. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with options for fuel oil prices, please provide the following information in a schedule format:

(a) the transaction date for the option;

(b) the option price or premium;

(c) the type of option;

(d) the time to expiration; and

(e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

Answer: Duke Energy Florida did not have any fuel oil options for August 2012 through July 2013.

54. For interrogatories 52 and 53 above, please explain any difference between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

Answer: The option premium prices represented in responses 52 are the actual prices that DEF executed the various financial option transactions. DEF executes all of its natural gas financial options at the prevailing market price that exists at the time the transactions are executed during the course of the trading day as consistent with previous years. DEF does not have observable market data for the natural gas option prices provided in responses 52.

55. Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2012, and ending July 31, 2013.

Answer:

Duke Energy Florida
For August 2012 through July 2013

Hedging Instrument	Fuel Type	Total
OTC Financial Instruments	Natural Gas	[redacted]
OTC Financial Instruments	Natural Gas - Storage	
OTC Financial Instruments	Heavy Oil	
OTC Financial Instruments	Light Oil	
OTC Financial Instruments	Light Heating Oil - River Barge - Fuel Surcharge Hedges	
OTC Financial Instruments	Light Heating Oil - Rail - Fuel Surcharge Hedges	
Total Net Cost		

56. For the twelve months beginning August 1, 2012, and ending July 31, 2013, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in DEF's risk management plan or otherwise stated in internal procedures governing DEF's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

Answer: As outlined in DEF's 2012 Risk Management Plan, due to the decline in overall forecasted heavy oil usage for future periods, DEF made the decision not to execute heavy oil hedges for periods beyond calendar year 2012, and targeted to hedge a minimum of [redacted] of forecasted heavy oil usage for calendar year 2012. As of December 2011, with respect to heavy oil, DEF was approximately [redacted] hedged for forecasted heavy oil usage for calendar year 2012 which was above the minimum target hedge percentage. DEF's actual hedge percentage for calendar year 2012 based on actual burns for heavy oil was approximately [redacted]. Given the actual to forecasted 2012 burn variances, the resulting actual hedge percentage for heavy oil was lower than the targeted minimum of [redacted] based on forecasted calendar year usage. As outlined in the Plan, actual hedge percentages for any monthly periods, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns.

57. Please provide a comparison of DEF's Risk Management Plans for 2013 and 2014.

Please describe any changes between the respective plans.

Answer: The overall substance of the key processes, oversight activities, controls, and purpose of risk documents and objectives of the 2014 Risk Management Plan are the same as the 2013 Risk Management Plan. With the completion of the merger between Duke Energy and Progress Energy and subsequent integration activities, there were administrative updates included in the 2014 Risk Management Plan resulting from the incorporation of similar documents that existed for both entities before the merger into common risk, credit, and limit documents. The updates are summarized below.

- On Page 13 of the 2014 Plan, paragraph 4 – Identify the Franchised Electric Risk Management Control Manual, DEF Franchised Electric Risk Limits, DEF Franchised Electric Credit Limits, Credit Policy and Credit Risk Limits.

- On Page 14 of the 2014 Plan, paragraph 4 – Identify the Franchised Electric Risk Management Control Manual, a Commodity Risk Policy, a Credit Policy, and DEF Franchised Electric Risk and Electric Credit Limits. In addition, the Company has the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority and the Duke Energy Commodities Approval Matrix from the Approval of Business Transactions policy that outline the approval requirements for procurement activities for respective individuals and management levels based on the tenor and estimated dollar amounts of agreement, subject to the requirements of the Approval of Business Transactions policy.

- 2014 Plan – Provided updated attachments, Attachment A – DEF Franchised Electric Risk Limits, Attachment G –DEF Franchised Electric Credit Limits, and Attachment I – Franchised Electric Risk Management Control Manual.

- 2013 Plan – Removed attachments, Attachment A – PEF Fuels & Power Optimization Risk Management Guidelines, Attachment G – PEF Fuel and Power Optimization Credit Risk Management Guidelines, and Attachment I – Trader Authorization – Gas and Emissions. These documents were replaced with the DEF Franchised Electric Risk Limits, DEF Franchised Electric Credit Limits, and Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority.

58. Regarding hedging activities, how does DEF assess and evaluate counter-party credit risk?

Answer: Credit Risk Management evaluates counterparties using a consistent analytic approach. The credit ratings are based on both external ratings and the evaluation of key counterparty attributes identified as leading indicators for financial performance and established, industry standard, and financial and credit metrics (e.g. leverage ratios, Funds from Operations, Cash Flow from Operations, Debt Service and Interest Coverage, Revenue trends, Profit Margins, Net Worth, Outstanding debt analysis and metric trend analysis, Bank Failure Ratio, Nonperforming Assets to Total Assets Ratio, etc.). The credit rating objectives promote an objective, fair, and consistent methodology to review counterparty candidates and establish and promote consistent risk standards. Evaluations are performed on an established frequency based on a counterparty's credit rating. Credit Risk Management uses news and credit rating alerts to monitor counterparties for any material changes or issues. The on-going monitoring of markets, industries, news wires, and peer groups generate information which would prompt an interim review if warranted.

59. For open hedging transactions since August 1, 2012, has DEF experienced any defaults by a counter-party? Please identify the counter-party and explain.

Answer: DEF has not experienced any defaults.

60. For all currently open hedging transactions, does DEF have any concern regarding default by a counter-party for any specific transaction? Please identify the counter-party and explain.

Answer: DEF does not have any concerns regarding any counter-party defaults for specific transactions.

61. Since January 1, 2012, has DEF stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? Please identify the counter-party and explain.

Answer: No. DEF has not stopped engaging in hedging transactions with a particular counterparty due to credit concerns since January 1, 2012.

62. Has DEF incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If so, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

Answer: No. DEF has not incurred any federal and/or state tax expenses (credits) on realized hedging gains (losses) associated with fuel expense over the past three years.

AFFIDAVIT

STATE OF North Carolina

COUNTY OF Mecklenburg

I hereby certify that on this 14th day of October, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Joseph McCallister, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 49 through 61 from STAFF'S SEVENTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 49-62) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of October, 2013.

Joseph McCallister

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

Notary Public: Rita G. Kale

My Commission Expires:
June 17, 2017

AFFIDAVIT

STATE OF Florida

COUNTY OF Pinellas

I hereby certify that on this 15th day of October, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Thomas G. Foster, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 62 from STAFF'S SEVENTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 49-62) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 15th day of October, 2013.

SUZANNE H. MILLER
MY COMMISSION # EE 854446
EXPIRES: March 27, 2017
Bonded Thru Notary Public Underwriters

Thomas G. Foster

Notary Public

My Commission Expires:
3/27/17

DEF Response to Staff 7th Rogs (Q49)
Dkt# 130001-EI

Attachments Bearing:

Bates Nos. PEF-13FL-001932 through PEF-13FL-001946

Question 45
2012 August Discretion Swap Hedges

REDACTED

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price	
8/1/2012	7/6/2007	FIXED SWAP	2126526	IFERC	HHUB			$7.170		
9/1/2012	7/6/2007	FIXED SWAP	2126527	IFERC	HHUB			$7.213		
10/1/2012	7/6/2007	FIXED SWAP	2126528	IFERC	HHUB			$7.313		
8/1/2012	7/11/2007	FIXED SWAP	2130389	IFERC	HHUB			$7.129		
9/1/2012	7/11/2007	FIXED SWAP	2130432	IFERC	HHUB			$7.172		
10/1/2012	7/11/2007	FIXED SWAP	2130433	IFERC	HHUB			$7.272		
8/1/2012	7/18/2007	FIXED SWAP	2140259	IFERC	HHUB			$7.312		
9/1/2012	7/18/2007	FIXED SWAP	2140260	IFERC	HHUB			$7.355		
10/1/2012	7/18/2007	FIXED SWAP	2140262	IFERC	HHUB			$7.455		
8/1/2012	8/14/2007	FIXED SWAP	2165072	IFERC	HHUB			$7.335		
9/1/2012	8/14/2007	FIXED SWAP	2165073	IFERC	HHUB			$7.375		
10/1/2012	8/14/2007	FIXED SWAP	2165074	IFERC	HHUB			$7.472		
8/1/2012	8/28/2007	FIXED SWAP	2181902	IFERC	HHUB			$7.112		
9/1/2012	8/28/2007	FIXED SWAP	2181906	IFERC	HHUB			$7.152		
10/1/2012	8/28/2007	FIXED SWAP	2181907	IFERC	HHUB			$7.249		
8/1/2012	9/12/2007	FIXED SWAP	2194795	IFERC	HHUB			$7.464		
9/1/2012	9/12/2007	FIXED SWAP	2194796	IFERC	HHUB			$7.496		
10/1/2012	9/12/2007	FIXED SWAP	2194797	IFERC	HHUB			$7.589		
8/1/2012	9/26/2007	FIXED SWAP	2209418	IFERC	HHUB			$7.241		
9/1/2012	9/26/2007	FIXED SWAP	2209417	IFERC	HHUB			$7.285		
10/1/2012	9/26/2007	FIXED SWAP	2209418	IFERC	HHUB			$7.341		
11/1/2012	9/26/2007	FIXED SWAP	2209419	IFERC	HHUB			$7.661		
12/1/2012	9/26/2007	FIXED SWAP	2209420	IFERC	HHUB			$7.976		
8/1/2012	10/3/2007	FIXED SWAP	2220223	IFERC	HHUB			$7.254		
9/1/2012	10/3/2007	FIXED SWAP	2220223	IFERC	HHUB			$7.274		
10/1/2012	10/3/2007	FIXED SWAP	2220224	IFERC	HHUB			$7.344		
8/1/2012	10/18/2007	FIXED SWAP	2244145	IFERC	HHUB			$7.499		
9/1/2012	10/18/2007	FIXED SWAP	2244146	IFERC	HHUB			$7.516		
10/1/2012	10/18/2007	FIXED SWAP	2244147	IFERC	HHUB			$7.572		
11/1/2012	10/18/2007	FIXED SWAP	2244148	IFERC	HHUB			$7.865		
12/1/2012	10/18/2007	FIXED SWAP	2244149	IFERC	HHUB			$8.170		
8/1/2012	11/6/2007	FIXED SWAP	2262119	IFERC	HHUB			$7.536		0.8%
9/1/2012	11/6/2007	FIXED SWAP	2262120	IFERC	HHUB			$7.557		
10/1/2012	11/6/2007	FIXED SWAP	2262121	IFERC	HHUB			$7.617		
11/1/2012	11/6/2007	FIXED SWAP	2262122	IFERC	HHUB			$7.917		
12/1/2012	11/6/2007	FIXED SWAP	2262123	IFERC	HHUB			$8.227		Avg for the Strip
8/1/2012	12/13/2007	FIXED SWAP	2278613	IFERC	HHUB			$7.809		
9/1/2012	12/13/2007	FIXED SWAP	2278614	IFERC	HHUB			$7.824		
10/1/2012	12/13/2007	FIXED SWAP	2278615	IFERC	HHUB			$7.879		
8/1/2012	12/27/2007	FIXED SWAP	2298611	IFERC	HHUB			$8.151		
9/1/2012	12/27/2007	FIXED SWAP	2298612	IFERC	HHUB			$8.181		
10/1/2012	12/27/2007	FIXED SWAP	2298613	IFERC	HHUB			$8.221		
8/1/2012	1/8/2008	FIXED SWAP	2324862	IFERC	HHUB			$7.963		
9/1/2012	1/8/2008	FIXED SWAP	2324864	IFERC	HHUB			$8.013		
10/1/2012	1/8/2008	FIXED SWAP	2324865	IFERC	HHUB			$8.083		
8/1/2012	2/13/2008	FIXED SWAP	2344863	IFERC	HHUB			$8.099		
9/1/2012	2/13/2008	FIXED SWAP	2344864	IFERC	HHUB			$8.116		
10/1/2012	2/13/2008	FIXED SWAP	2344865	IFERC	HHUB			$8.169		
8/1/2012	4/2/2008	FIXED SWAP	2372713	IFERC	HHUB			$8.425		1.3%
9/1/2012	4/2/2008	FIXED SWAP	2372714	IFERC	HHUB			$8.449		
10/1/2012	4/2/2008	FIXED SWAP	2372715	IFERC	HHUB			$8.539		
11/1/2012	4/2/2008	FIXED SWAP	2372716	IFERC	HHUB			$8.797		
12/1/2012	4/2/2008	FIXED SWAP	2372717	IFERC	HHUB			$9.162		Avg for the Strip
8/1/2012	4/18/2008	FIXED SWAP	2403490	IFERC	HHUB			$8.855		
9/1/2012	4/18/2008	FIXED SWAP	2403492	IFERC	HHUB			$8.853		
10/1/2012	4/18/2008	FIXED SWAP	2403494	IFERC	HHUB			$8.875		
8/1/2012	4/25/2008	FIXED SWAP	2407925	IFERC	HHUB			$9.039		
9/1/2012	4/25/2008	FIXED SWAP	2407927	IFERC	HHUB			$9.139		
10/1/2012	4/25/2008	FIXED SWAP	2407928	IFERC	HHUB			$9.189		
8/1/2012	5/23/2008	FIXED SWAP	2437253	NYMEX	NG			$9.679		
9/1/2012	5/23/2008	FIXED SWAP	2437255	NYMEX	NG			$9.689		
10/1/2012	5/23/2008	FIXED SWAP	2437256	NYMEX	NG			$9.779		
8/1/2012	6/4/2008	FIXED SWAP	2441273	NYMEX	NG			$9.719		
9/1/2012	6/4/2008	FIXED SWAP	2441274	NYMEX	NG			$9.739		
10/1/2012	6/4/2008	FIXED SWAP	2441275	NYMEX	NG			$9.819		

130001 Hearing Exhibits - 00359

PEF-13-FL-001932

Question 49
29 2 August - December Swap Hedges

REDACTED

9/1/2012	8/31/2006	FIXED SWAP	2460445	NYMEX	NG	[redacted]	$10 065
9/1/2012	8/31/2006	FIXED SWAP	2460450	NYMEX	NG	[redacted]	$10 085
10/1/2012	9/1/2006	FIXED SWAP	2460451	NYMEX	NG	[redacted]	$10 170
9/1/2012	9/25/2006	FIXED SWAP	2457892	NYMEX	NG	[redacted]	$10 295
8/1/2012	6/25/2006	FIXED SWAP	2457872	NYMEX	NG	[redacted]	$10 315
10/1/2012	6/25/2006	FIXED SWAP	2457824	NYMEX	NG	[redacted]	$10 405
8/1/2012	7/25/2006	FIXED SWAP	2466935	NYMEX	NG	[redacted]	$9 926
9/1/2012	7/25/2006	FIXED SWAP	2466936	NYMEX	NG	[redacted]	$9 948
10/1/2012	7/25/2006	FIXED SWAP	2468937	NYMEX	NG	[redacted]	$10 038
8/1/2012	7/25/2006	FIXED SWAP	2479885	NYMEX	NG	[redacted]	$6 327
9/1/2012	7/25/2006	FIXED SWAP	2479890	NYMEX	NG	[redacted]	$6 547
10/1/2012	7/25/2006	FIXED SWAP	2479891	NYMEX	NG	[redacted]	$6 437
8/1/2012	10/31/2006	FIXED SWAP	2579384	IFHC	H-UB	[redacted]	$7 548
9/1/2012	10/31/2006	FIXED SWAP	2579385	IFHC	H-UB	[redacted]	$7 574
10/1/2012	10/31/2006	FIXED SWAP	2579386	IFHC	H-UB	[redacted]	$7 664
8/1/2012	11/29/2006	FIXED SWAP	2618054	NYMEX	NG	[redacted]	$7 773
9/1/2012	11/29/2006	FIXED SWAP	2618055	NYMEX	NG	[redacted]	$7 897
10/1/2012	11/29/2006	FIXED SWAP	2618056	NYMEX	NG	[redacted]	$7 887
11/1/2012	12/1/2006	FIXED SWAP	2625161	NYMEX	NG	[redacted]	$7 662
12/1/2012	12/1/2006	FIXED SWAP	2625162	NYMEX	NG	[redacted]	$8 072
8/1/2012	12/31/2006	FIXED SWAP	2640230	NYMEX	NG	[redacted]	$6 973
9/1/2012	12/31/2006	FIXED SWAP	2640231	NYMEX	NG	[redacted]	$6 996
10/1/2012	12/31/2006	FIXED SWAP	2640232	NYMEX	NG	[redacted]	$7 078
11/1/2012	12/31/2006	FIXED SWAP	2640233	NYMEX	NG	[redacted]	$7 303
12/1/2012	12/31/2006	FIXED SWAP	2640234	NYMEX	NG	[redacted]	$7 553
8/1/2012	1/1/2007	FIXED SWAP	2655370	NYMEX	NG	[redacted]	$6 980
9/1/2012	1/1/2007	FIXED SWAP	2655371	NYMEX	NG	[redacted]	$7 009
10/1/2012	1/1/2007	FIXED SWAP	2655372	NYMEX	NG	[redacted]	$7 086
11/1/2012	1/1/2007	FIXED SWAP	2655373	NYMEX	NG	[redacted]	$7 347
12/1/2012	1/1/2007	FIXED SWAP	2655374	NYMEX	NG	[redacted]	$7 655
8/1/2012	12/4/2006	FIXED SWAP	2950205	NYMEX	NG	[redacted]	$6 420
9/1/2012	12/4/2006	FIXED SWAP	2950206	NYMEX	NG	[redacted]	$6 455
10/1/2012	12/4/2006	FIXED SWAP	2950207	NYMEX	NG	[redacted]	$6 560
8/1/2012	1/31/2007	FIXED SWAP	2978485	NYMEX	NG	[redacted]	$6 249
9/1/2012	1/31/2007	FIXED SWAP	2978487	NYMEX	NG	[redacted]	$6 289
10/1/2012	1/31/2007	FIXED SWAP	2978488	NYMEX	NG	[redacted]	$6 399
8/1/2012	2/1/2007	FIXED SWAP	2987078	NYMEX	NG	[redacted]	$5 957
9/1/2012	2/1/2007	FIXED SWAP	2987079	NYMEX	NG	[redacted]	$5 992
10/1/2012	2/1/2007	FIXED SWAP	2987080	NYMEX	NG	[redacted]	$6 102
8/1/2012	3/29/2007	FIXED SWAP	3011635	NYMEX	NG	[redacted]	$5 574
9/1/2012	3/29/2007	FIXED SWAP	3011636	NYMEX	NG	[redacted]	$5 609
10/1/2012	3/29/2007	FIXED SWAP	3011637	NYMEX	NG	[redacted]	$5 711
8/1/2012	4/27/2007	FIXED SWAP	3043385	NYMEX	NG	[redacted]	$5 703
9/1/2012	4/27/2007	FIXED SWAP	3043386	NYMEX	NG	[redacted]	$5 738
10/1/2012	4/27/2007	FIXED SWAP	3043403	NYMEX	NG	[redacted]	$5 831
8/1/2012	5/29/2007	FIXED SWAP	3068934	NYMEX	NG	[redacted]	$5 598
9/1/2012	5/29/2007	FIXED SWAP	3068935	NYMEX	NG	[redacted]	$5 628
10/1/2012	5/29/2007	FIXED SWAP	3068936	NYMEX	NG	[redacted]	$5 723
8/1/2012	6/26/2007	FIXED SWAP	3075620	NYMEX	NG	[redacted]	$5 578
9/1/2012	6/26/2007	FIXED SWAP	3075621	NYMEX	NG	[redacted]	$5 603
10/1/2012	6/26/2007	FIXED SWAP	3075622	NYMEX	NG	[redacted]	$5 696
8/1/2012	6/24/2010	FIXED SWAP	3079512	NYMEX	NG	[redacted]	$5 586
9/1/2012	6/24/2010	FIXED SWAP	3079513	NYMEX	NG	[redacted]	$5 715
10/1/2012	6/24/2010	FIXED SWAP	3079514	NYMEX	NG	[redacted]	$5 805
8/1/2012	7/1/2010	FIXED SWAP	3084029	NYMEX	NG	[redacted]	$5 538
9/1/2012	7/1/2010	FIXED SWAP	3084030	NYMEX	NG	[redacted]	$5 567
10/1/2012	7/1/2010	FIXED SWAP	3084031	NYMEX	NG	[redacted]	$5 656
8/1/2012	7/29/2010	FIXED SWAP	3092417	NYMEX	NG	[redacted]	$5 424
9/1/2012	7/29/2010	FIXED SWAP	3092422	NYMEX	NG	[redacted]	$5 434
10/1/2012	7/29/2010	FIXED SWAP	3092423	NYMEX	NG	[redacted]	$5 525
8/1/2012	8/4/2010	FIXED SWAP	3097817	NYMEX	NG	[redacted]	$5 375
9/1/2012	8/4/2010	FIXED SWAP	3097818	NYMEX	NG	[redacted]	$5 403
10/1/2012	8/4/2010	FIXED SWAP	3097819	NYMEX	NG	[redacted]	$5 490
8/1/2012	8/19/2010	FIXED SWAP	3103835	NYMEX	NG	[redacted]	$5 251
9/1/2012	8/19/2010	FIXED SWAP	3103836	NYMEX	NG	[redacted]	$5 279
10/1/2012	8/19/2010	FIXED SWAP	3103837	NYMEX	NG	[redacted]	$5 365
8/1/2012	8/30/2010	FIXED SWAP	3107669	NYMEX	NG	[redacted]	$5 207
9/1/2012	8/30/2010	FIXED SWAP	3107670	NYMEX	NG	[redacted]	$5 221
10/1/2012	8/30/2010	FIXED SWAP	3107671	NYMEX	NG	[redacted]	$5 310

Exhibit 49

2012 August - December Swap Hedges

REDACTED

8/1/2012	9/30/2010	FIXED SWAP	3122706	NYMEX	NG	[redacted]	$4.973	[redacted]
9/1/2012	9/30/2010	FIXED SWAP	3122706	NYMEX	NG		$4.991	
10/1/2012	9/30/2010	FIXED SWAP	3122707	NYMEX	NG		$5.367	
8/1/2012	11/19/2010	FIXED SWAP	3159799	NYMEX	NG		$4.875	
9/1/2012	11/19/2010	FIXED SWAP	3159796	NYMEX	NG		$4.899	
10/1/2012	11/19/2010	FIXED SWAP	3159800	NYMEX	NG		$4.977	
8/1/2012	11/22/2010	FIXED SWAP	3161687	NYMEX	NG		$5.035	
9/1/2012	11/22/2010	FIXED SWAP	3161688	NYMEX	NG		$4.951	
10/1/2012	11/22/2010	FIXED SWAP	3161689	NYMEX	NG		$5.124	
8/1/2012	12/14/2010	FIXED SWAP	3170805	NYMEX	NG		$4.861	
9/1/2012	12/14/2010	FIXED SWAP	3170807	NYMEX	NG		$4.879	
10/1/2012	12/14/2010	FIXED SWAP	3170808	NYMEX	NG		$4.953	
8/1/2012	1/6/2011	FIXED SWAP	3182046	NYMEX	NG		$4.890	
9/1/2012	1/6/2011	FIXED SWAP	3182047	NYMEX	NG		$4.908	
10/1/2012	1/6/2011	FIXED SWAP	3182048	NYMEX	NG		$4.965	
8/1/2012	2/4/2011	FIXED SWAP	3200032	NYMEX	NG		$4.913	
9/1/2012	2/4/2011	FIXED SWAP	3200033	NYMEX	NG		$4.923	
10/1/2012	2/4/2011	FIXED SWAP	3200032	NYMEX	NG		$4.980	
8/1/2012	2/7/2011	FIXED SWAP	3201573	NYMEX	NG		$4.817	
9/1/2012	2/7/2011	FIXED SWAP	3201574	NYMEX	NG		$4.837	
10/1/2012	2/7/2011	FIXED SWAP	3201575	NYMEX	NG		$4.893	
8/1/2012	2/7/2011	FIXED SWAP	3201407	NYMEX	NG		$4.817	
9/1/2012	2/7/2011	FIXED SWAP	3201408	NYMEX	NG		$4.827	
10/1/2012	2/7/2011	FIXED SWAP	3201404	NYMEX	NG		$4.887	
11/1/2012	2/8/2011	FIXED SWAP	3202226	NYMEX	NG		$4.986	
12/1/2012	2/8/2011	FIXED SWAP	3202227	NYMEX	NG		$5.201	
11/1/2012	2/16/2011	FIXED SWAP	3207364	NYMEX	NG		$4.920	
12/1/2012	2/16/2011	FIXED SWAP	3207365	NYMEX	NG		$5.116	
8/1/2012	3/2/2011	FIXED SWAP	3213921	NYMEX	NG		$4.674	
9/1/2012	3/2/2011	FIXED SWAP	3213922	NYMEX	NG		$4.684	
10/1/2012	3/2/2011	FIXED SWAP	3213923	NYMEX	NG		$4.732	
11/1/2012	3/2/2011	FIXED SWAP	3213902	NYMEX	NG		$4.899	
12/1/2012	3/2/2011	FIXED SWAP	3213903	NYMEX	NG		$5.115	
11/1/2012	3/10/2011	FIXED SWAP	3218757	NYMEX	NG		$4.914	
12/1/2012	3/10/2011	FIXED SWAP	3218758	NYMEX	NG		$5.141	
8/1/2012	3/11/2011	FIXED SWAP	3218240	NYMEX	NG		$4.734	
9/1/2012	3/11/2011	FIXED SWAP	3218241	NYMEX	NG		$4.744	
10/1/2012	3/11/2011	FIXED SWAP	3218242	NYMEX	NG		$4.791	
11/1/2012	3/14/2011	FIXED SWAP	3222397	NYMEX	NG		$5.167	
12/1/2012	3/14/2011	FIXED SWAP	3222398	NYMEX	NG		$5.373	
8/1/2012	3/24/2011	FIXED SWAP	3224666	NYMEX	NG		$4.975	
9/1/2012	3/24/2011	FIXED SWAP	3224667	NYMEX	NG		$4.979	
10/1/2012	3/24/2011	FIXED SWAP	3224668	NYMEX	NG		$5.078	
11/1/2012	3/25/2011	FIXED SWAP	3225053	NYMEX	NG		$5.267	
12/1/2012	3/25/2011	FIXED SWAP	3225053	NYMEX	NG		$5.477	
11/1/2012	4/4/2011	FIXED SWAP	3231883	NYMEX	NG		$5.187	
12/1/2012	4/4/2011	FIXED SWAP	3231884	NYMEX	NG		$5.471	
8/1/2012	4/8/2011	FIXED SWAP	3273801	NYMEX	NG		$4.826	
9/1/2012	4/8/2011	FIXED SWAP	3273802	NYMEX	NG		$4.626	
10/1/2012	4/8/2011	FIXED SWAP	3273803	NYMEX	NG		$4.684	
11/1/2012	4/13/2011	FIXED SWAP	3274072	NYMEX	NG		$5.063	
12/1/2012	4/13/2011	FIXED SWAP	3274073	NYMEX	NG		$5.320	
8/1/2012	4/18/2011	FIXED SWAP	3277276	NYMEX	NG		$4.823	
9/1/2012	4/18/2011	FIXED SWAP	3277277	NYMEX	NG		$4.835	
10/1/2012	4/18/2011	FIXED SWAP	3277278	NYMEX	NG		$4.889	
11/1/2012	5/5/2011	FIXED SWAP	3295554	NYMEX	NG		$5.073	
12/1/2012	5/5/2011	FIXED SWAP	3295555	NYMEX	NG		$5.295	
8/1/2012	5/6/2011	FIXED SWAP	3296304	NYMEX	NG		$4.832	
9/1/2012	5/6/2011	FIXED SWAP	3296305	NYMEX	NG		$4.842	
10/1/2012	5/6/2011	FIXED SWAP	3296306	NYMEX	NG		$4.892	
11/1/2012	5/9/2011	FIXED SWAP	3297397	NYMEX	NG		$4.993	29%
12/1/2012	5/9/2011	FIXED SWAP	3297398	NYMEX	NG		$5.217	Avg for the Strip
8/1/2012	5/11/2011	FIXED SWAP	3298481	NYMEX	NG		$4.804	
9/1/2012	5/11/2011	FIXED SWAP	3298482	NYMEX	NG		$4.814	
10/1/2012	5/11/2011	FIXED SWAP	3298483	NYMEX	NG		$4.857	
8/1/2012	5/13/2011	FIXED SWAP	3301242	NYMEX	NG		$4.852	
9/1/2012	5/13/2011	FIXED SWAP	3301243	NYMEX	NG		$4.862	
10/1/2012	5/13/2011	FIXED SWAP	3301244	NYMEX	NG		$4.914	
11/1/2012	5/13/2011	FIXED SWAP	3301231	NYMEX	NG		$5.077	

PEF-13-FL-001934

130001 Hearing Exhibits - 00361

Question 49
2012 August - December Swap Hedges

REDACTED

12/1/2012	6/13/2011	FIXED SWAP	3307232	NYMEX	NG	[redacted]	$5.096	[redacted]	
8/1/2012	6/24/2011	FIXED SWAP	3309077	NYMEX	NG	[redacted]	$4.951	[redacted]	
9/1/2012	6/24/2011	FIXED SWAP	3309078	NYMEX	NG	[redacted]	$4.921	[redacted]	
10/1/2012	6/24/2011	FIXED SWAP	3309079	NYMEX	NG	[redacted]	$4.970	[redacted]	
11/1/2012	6/24/2011	FIXED SWAP	3309046	NYMEX	NG	[redacted]	$5.172	[redacted]	
12/1/2012	6/24/2011	FIXED SWAP	3309047	NYMEX	NG	[redacted]	$5.344	[redacted]	
1/1/2013	6/24/2011	FIXED SWAP	3317397	NYMEX	NG	[redacted]	$5.175	[redacted]	
12/1/2012	6/27/2011	FIXED SWAP	3317393	NYMEX	NG	[redacted]	$5.390	[redacted]	
11/1/2012	6/28/2011	FIXED SWAP	3321928	NYMEX	NG	[redacted]	$5.270	[redacted]	
12/1/2012	6/28/2011	FIXED SWAP	3321929	NYMEX	NG	[redacted]	$5.472	[redacted]	
8/1/2012	6/8/2011	FIXED SWAP	3329744	NYMEX	NG	[redacted]	$4.990	[redacted]	
9/1/2012	6/8/2011	FIXED SWAP	3329745	NYMEX	NG	[redacted]	$4.969	[redacted]	
10/1/2012	6/8/2011	FIXED SWAP	3329746	NYMEX	NG	[redacted]	$5.044	[redacted]	
11/1/2012	6/9/2011	FIXED SWAP	3329691	NYMEX	NG	[redacted]	$5.181	[redacted]	4.2% Avg for the Strip
12/1/2012	6/9/2011	FIXED SWAP	3329692	NYMEX	NG	[redacted]	$5.366	[redacted]	
8/1/2012	6/16/2011	FIXED SWAP	3334005	NYMEX	NG	[redacted]	$4.657	[redacted]	
9/1/2012	6/16/2011	FIXED SWAP	3334006	NYMEX	NG	[redacted]	$4.663	[redacted]	
10/1/2012	6/16/2011	FIXED SWAP	3334007	NYMEX	NG	[redacted]	$4.938	[redacted]	
11/1/2012	6/16/2011	FIXED SWAP	3334008	NYMEX	NG	[redacted]	$5.037	[redacted]	3.4% Avg for the Strip
12/1/2012	6/16/2011	FIXED SWAP	3334009	NYMEX	NG	[redacted]	$5.257	[redacted]	
8/1/2012	6/28/2011	FIXED SWAP	3341161	NYMEX	NG	[redacted]	$4.761	[redacted]	
9/1/2012	6/28/2011	FIXED SWAP	3341162	NYMEX	NG	[redacted]	$4.771	[redacted]	
10/1/2012	6/28/2011	FIXED SWAP	3341163	NYMEX	NG	[redacted]	$4.811	[redacted]	
11/1/2012	6/28/2011	FIXED SWAP	3341164	NYMEX	NG	[redacted]	$4.947	[redacted]	
12/1/2012	6/28/2011	FIXED SWAP	3341165	NYMEX	NG	[redacted]	$5.164	[redacted]	
8/1/2012	7/7/2011	FIXED SWAP	3346907	NYMEX	NG	[redacted]	$4.656	[redacted]	
9/1/2012	7/7/2011	FIXED SWAP	3346908	NYMEX	NG	[redacted]	$4.666	[redacted]	
10/1/2012	7/7/2011	FIXED SWAP	3346909	NYMEX	NG	[redacted]	$4.706	[redacted]	
11/1/2012	7/8/2011	FIXED SWAP	3347571	NYMEX	NG	[redacted]	$4.921	[redacted]	
12/1/2012	7/8/2011	FIXED SWAP	3347572	NYMEX	NG	[redacted]	$5.152	[redacted]	
8/1/2012	7/12/2011	FIXED SWAP	3349570	NYMEX	NG	[redacted]	$4.784	[redacted]	
9/1/2012	7/12/2011	FIXED SWAP	3349571	NYMEX	NG	[redacted]	$4.793	[redacted]	
10/1/2012	7/12/2011	FIXED SWAP	3349572	NYMEX	NG	[redacted]	$4.834	[redacted]	
11/1/2012	7/12/2011	FIXED SWAP	3349528	NYMEX	NG	[redacted]	$4.983	[redacted]	
12/1/2012	7/12/2011	FIXED SWAP	3349579	NYMEX	NG	[redacted]	$5.210	[redacted]	
8/1/2012	7/14/2011	FIXED SWAP	3350847	NYMEX	NG	[redacted]	$4.796	[redacted]	
9/1/2012	7/14/2011	FIXED SWAP	3350848	NYMEX	NG	[redacted]	$4.805	[redacted]	
10/1/2012	7/14/2011	FIXED SWAP	3350849	NYMEX	NG	[redacted]	$4.846	[redacted]	
8/1/2012	7/18/2011	FIXED SWAP	3353522	NYMEX	NG	[redacted]	$4.874	[redacted]	
9/1/2012	7/18/2011	FIXED SWAP	3353523	NYMEX	NG	[redacted]	$4.882	[redacted]	
10/1/2012	7/18/2011	FIXED SWAP	3353524	NYMEX	NG	[redacted]	$4.923	[redacted]	
11/1/2012	7/18/2011	FIXED SWAP	3353525	NYMEX	NG	[redacted]	$5.053	[redacted]	
12/1/2012	7/18/2011	FIXED SWAP	3353526	NYMEX	NG	[redacted]	$5.289	[redacted]	
8/1/2012	7/21/2011	FIXED SWAP	3354885	FERC	HHUB	[redacted]	$4.761	[redacted]	
9/1/2012	7/21/2011	FIXED SWAP	3354886	FERC	HHUB	[redacted]	$4.768	[redacted]	
11/1/2012	7/27/2011	FIXED SWAP	3356364	NYMEX	NG	[redacted]	$4.954	[redacted]	
12/1/2012	7/27/2011	FIXED SWAP	3356366	NYMEX	NG	[redacted]	$5.172	[redacted]	
8/1/2012	7/28/2011	FIXED SWAP	3366886	FERC	HHUB	[redacted]	$4.658	[redacted]	
9/1/2012	7/28/2011	FIXED SWAP	3366887	FERC	HHUB	[redacted]	$4.666	[redacted]	
11/1/2012	7/28/2011	FIXED SWAP	3367372	NYMEX	NG	[redacted]	$4.796	[redacted]	
12/1/2012	7/28/2011	FIXED SWAP	3367373	NYMEX	NG	[redacted]	$5.026	[redacted]	
8/1/2012	8/2/2011	FIXED SWAP	3366626	IFERC	HHUB	[redacted]	$4.613	[redacted]	
9/1/2012	8/2/2011	FIXED SWAP	3366627	IFERC	HHUB	[redacted]	$4.622	[redacted]	
8/1/2012	8/4/2011	FIXED SWAP	3371666	NYMEX	NG	[redacted]	$4.463	[redacted]	
9/1/2012	8/4/2011	FIXED SWAP	3371667	NYMEX	NG	[redacted]	$4.471	[redacted]	
10/1/2012	8/4/2011	FIXED SWAP	3371668	NYMEX	NG	[redacted]	$4.536	[redacted]	
8/1/2012	8/4/2011	FIXED SWAP	3371625	NYMEX	NG	[redacted]	$4.463	[redacted]	
9/1/2012	8/4/2011	FIXED SWAP	3371626	NYMEX	NG	[redacted]	$4.471	[redacted]	
10/1/2012	8/4/2011	FIXED SWAP	3371627	NYMEX	NG	[redacted]	$4.536	[redacted]	
11/1/2012	8/4/2011	FIXED SWAP	3371669	NYMEX	NG	[redacted]	$4.671	[redacted]	2.9%
12/1/2012	8/4/2011	FIXED SWAP	3371670	NYMEX	NG	[redacted]	$4.916	[redacted]	Avg for the Strip
11/1/2012	8/4/2011	FIXED SWAP	3371629	NYMEX	NG	[redacted]	$4.671	[redacted]	4.0%
12/1/2012	8/4/2011	FIXED SWAP	3371628	NYMEX	NG	[redacted]	$4.916	[redacted]	Avg for the Strip
8/1/2012	8/5/2011	FIXED SWAP	3372251	IFERC	HHUB	[redacted]	$4.490	[redacted]	
9/1/2012	8/5/2011	FIXED SWAP	3372252	IFERC	HHUB	[redacted]	$4.503	[redacted]	
8/1/2012	8/5/2011	FIXED SWAP	3372264	IFERC	HHUB	[redacted]	$4.495	[redacted]	
9/1/2012	8/5/2011	FIXED SWAP	3372265	IFERC	HHUB	[redacted]	$4.503	[redacted]	
11/1/2012	8/5/2011	FIXED SWAP	3372241	NYMEX	NG	[redacted]	$4.704	[redacted]	
12/1/2012	8/5/2011	FIXED SWAP	3372242	NYMEX	NG	[redacted]	$4.946	[redacted]	

PEF-13-FL-001935

130001 Hearing Exhibits - 00362

Question 43

2012 August - December Swap Hedges

REDACTED

8/1/2012	8/8/2011	FIXED SWAP	3373795	IFERC	HHUB	[redacted]	$4.493	[redacted]
9/1/2012	8/8/2011	FIXED SWAP	3373796	IFERC	HHUB		$4.507	
11/1/2012	8/8/2011	FIXED SWAP	3373878	NYMEX	NG		$4.703	2.9%
12/1/2012	8/8/2011	FIXED SWAP	3373879	NYMEX	NG		$4.945	Avg for the Strip
8/1/2012	8/8/2011	FIXED SWAP	3374387	IFERC	HHUB		$4.534	
9/1/2012	8/8/2011	FIXED SWAP	3374388	IFERC	HHUB		$4.538	
11/1/2012	8/15/2011	FIXED SWAP	3377740	NYMEX	NG		$4.753	
12/1/2012	8/15/2011	FIXED SWAP	3377741	NYMEX	NG		$4.990	
8/1/2012	8/17/2011	FIXED SWAP	3379030	IFERC	HHUB		$4.491	
9/1/2012	8/17/2011	FIXED SWAP	3379031	IFERC	HHUB		$4.497	
11/1/2012	8/17/2011	FIXED SWAP	3379136	NYMEX	NG		$4.857	3.1%
12/1/2012	8/17/2011	FIXED SWAP	3379137	NYMEX	NG		$4.944	Avg for the Strip
8/1/2012	8/25/2011	FIXED SWAP	3383887	IFERC	HHUB		$4.410	
9/1/2012	8/25/2011	FIXED SWAP	3383888	IFERC	HHUB		$4.415	
11/1/2012	8/25/2011	FIXED SWAP	3383968	NYMEX	NG		$4.606	2.7%
12/1/2012	8/25/2011	FIXED SWAP	3383969	NYMEX	NG		$4.854	Avg for the Strip
11/1/2012	8/31/2011	FIXED SWAP	3396674	NYMEX	NG		$4.761	
12/1/2012	8/31/2011	FIXED SWAP	3396675	NYMEX	NG		$5.013	
8/1/2012	9/2/2011	FIXED SWAP	3388481	IFERC	HHUB		$4.437	
9/1/2012	9/2/2011	FIXED SWAP	3388482	IFERC	HHUB		$4.438	
9/1/2012	9/14/2011	FIXED SWAP	3394490	NYMEX	NG		$4.515	
11/1/2012	9/14/2011	FIXED SWAP	3394491	NYMEX	NG		$4.518	
12/1/2012	9/14/2011	FIXED SWAP	3394492	NYMEX	NG		$4.548	
11/1/2012	9/16/2011	FIXED SWAP	3395981	NYMEX	NG		$4.604	2.9%
12/1/2012	9/16/2011	FIXED SWAP	3395982	NYMEX	NG		$4.859	Avg for the Strip
8/1/2012	9/23/2011	FIXED SWAP	3399664	NYMEX	NG		$4.284	
9/1/2012	9/23/2011	FIXED SWAP	3399665	NYMEX	NG		$4.288	
10/1/2012	9/23/2011	FIXED SWAP	3399666	NYMEX	NG		$4.321	
11/1/2012	10/6/2011	FIXED SWAP	3448434	NYMEX	NG		$4.386	2.5%
12/1/2012	10/6/2011	FIXED SWAP	3448435	NYMEX	NG		$4.674	Avg for the Strip
9/1/2012	10/7/2011	FIXED SWAP	3455145	NYMEX	NG		$4.118	
9/1/2012	10/7/2011	FIXED SWAP	3455146	NYMEX	NG		$4.118	
10/1/2012	10/7/2011	FIXED SWAP	3455147	NYMEX	NG		$4.152	
11/1/2012	10/11/2011	FIXED SWAP	3456970	NYMEX	NG		$4.312	2.3%
12/1/2012	10/11/2011	FIXED SWAP	3456971	NYMEX	NG		$4.587	Avg for the Strip
11/1/2012	10/13/2011	FIXED SWAP	3461246	NYMEX	NG		$4.246	3.4%
12/1/2012	10/13/2011	FIXED SWAP	3461247	NYMEX	NG		$4.516	Avg for the Strip
8/1/2012	10/13/2011	FIXED SWAP	3461218	NYMEX	NG		$4.077	
9/1/2012	10/13/2011	FIXED SWAP	3461219	NYMEX	NG		$4.077	
10/1/2012	10/13/2011	FIXED SWAP	3461220	NYMEX	NG		$4.112	
8/1/2012	10/27/2011	FIXED SWAP	3463105	IFERC	TRNSZ4		$4.072	
9/1/2012	10/27/2011	FIXED SWAP	3463106	IFERC	TRNSZ4		$4.072	
10/1/2012	10/27/2011	FIXED SWAP	3463107	IFERC	TRNSZ4		$4.107	
8/1/2012	10/27/2011	FIXED SWAP	3472728	IFERC	TRNSZ4		$4.042	
9/1/2012	10/27/2011	FIXED SWAP	3472729	IFERC	TRNSZ4		$4.044	
10/1/2012	10/27/2011	FIXED SWAP	3472730	IFERC	TRNSZ4		$4.084	
11/1/2012	10/27/2011	FIXED SWAP	3472648	IFERC	HHUB		$4.211	3.5%
12/1/2012	10/27/2011	FIXED SWAP	3472649	IFERC	HHUB		$4.474	Avg for the Strip
8/1/2012	11/4/2011	FIXED SWAP	3478150	IFERC	TRNSZ4		$4.074	
9/1/2012	11/4/2011	FIXED SWAP	3478151	IFERC	TRNSZ4		$4.098	
10/1/2012	11/4/2011	FIXED SWAP	3478152	IFERC	TRNSZ4		$4.084	
11/1/2012	11/4/2011	FIXED SWAP	3478276	NYMEX	NG		$4.195	3.9%
12/1/2012	11/4/2011	FIXED SWAP	3478277	NYMEX	NG		$4.456	Avg for the Strip
8/1/2012	11/7/2011	FIXED SWAP	3479619	IFERC	TRNSZ4		$3.952	
9/1/2012	11/7/2011	FIXED SWAP	3479620	IFERC	TRNSZ4		$3.954	
10/1/2012	11/7/2011	FIXED SWAP	3479621	IFERC	TRNSZ4		$3.990	
11/1/2012	11/7/2011	FIXED SWAP	3479622	NYMEX	NG		$4.127	3.2%
12/1/2012	11/7/2011	FIXED SWAP	3479623	NYMEX	NG		$4.395	Avg for the Strip
8/1/2012	11/9/2011	FIXED SWAP	3484200	IFERC	TRNSZ4		$3.899	
9/1/2012	11/9/2011	FIXED SWAP	3484201	IFERC	TRNSZ4		$3.901	
10/1/2012	11/9/2011	FIXED SWAP	3484202	IFERC	TRNSZ4		$3.936	
11/1/2012	11/14/2011	FIXED SWAP	3490396	NYMEX	NG		$3.969	3.8%
12/1/2012	11/14/2011	FIXED SWAP	3490397	NYMEX	NG		$4.229	Avg for the Strip
8/1/2012	12/9/2011	FIXED SWAP	3509004	NYMEX	NG		$3.573	
9/1/2012	12/9/2011	FIXED SWAP	3509005	NYMEX	NG		$3.577	
10/1/2012	12/9/2011	FIXED SWAP	3509007	NYMEX	NG		$3.613	
11/1/2012	12/12/2011	FIXED SWAP	3509914	IFERC	HHUB		$3.686	3.9%
12/1/2012	12/12/2011	FIXED SWAP	3509915	IFERC	HHUB		$3.973	Avg for the Strip
8/1/2012	12/14/2011	FIXED SWAP	3503600	IFERC	TRNSZ4		$3.459	

130001 Hearing Exhibits - 00363

PEF-13-FL-001936

Question 51

23 2 August - December Swap Hedges

REDACTED

8/1/2012	12/14/2012	FIXED SWAP	3503801	IFERC	TRNSZ4	[redacted]	$3.452	[redacted]	
12/1/2012	12/14/2012	FIXED SWAP	3503836	IFERC	TRNSZ4		$3.468		
8/1/2012	12/28/2012	FIXED SWAP	3508705	IFERC	TRNSZ4		$3.470		
8/1/2012	12/28/2012	FIXED SWAP	3508796	IFERC	TRNSZ4		$3.470		
10/1/2012	12/28/2012	FIXED SWAP	3508897	IFERC	TRNSZ4		$3.452		
11/1/2012	12/28/2012	FIXED SWAP	3508876	IFERC	HHUB		$3.583	4.6% Avg for the Strip	
12/1/2012	12/28/2012	FIXED SWAP	3508877	IFERC	HHUB		$3.803		
8/1/2012	12/29/2012	FIXED SWAP	3509356	IFERC	TRNSZ4		$3.324		
9/1/2012	12/29/2012	FIXED SWAP	3509366	IFERC	TRNSZ4		$3.330		
11/1/2012	1/1/2012	FIXED SWAP	3514190	IFERC	HHUB		$3.295	4.2% Avg for the Strip	
12/1/2012	1/1/2012	FIXED SWAP	3514191	IFERC	HHUB		$3.580		
8/1/2012	1/26/2012	FIXED SWAP	3521428	NYMEX	NG		$2.007		
11/1/2012	1/30/2012	FIXED SWAP	3522740	NYMEX	NG		$3.242	5.1% Avg for the Strip	Avg for entire strip was 0.9%
12/1/2012	1/30/2012	FIXED SWAP	3522741	NYMEX	NG		$3.612		
8/1/2012	1/31/2012	FIXED SWAP	3523059	IFERC	TRNSZ4		$2.904		
8/1/2012	2/1/2012	FIXED SWAP	3525041	IFERC	TRNSZ4		$2.872		
8/1/2012	2/1/2012	FIXED SWAP	3526023	IFERC	TRNSZ4		$2.980		
11/1/2012	2/1/2012	FIXED SWAP	3526029	IFERC	HHUB		$3.182	5.4% Avg for the Strip	Avg for entire strip was 0.6%
12/1/2012	2/1/2012	FIXED SWAP	3526027	IFERC	HHUB		$3.461		
8/1/2012	2/1/2012	FIXED SWAP	3526156	IFERC	TRNSZ4		$2.966		
11/1/2012	2/29/2012	FIXED SWAP	3534314	IFERC	HHUB		$3.053	5.1% Avg for the Strip	Avg for entire strip was 0.1%
12/1/2012	2/28/2012	FIXED SWAP	3534315	IFERC	HHUB		$3.352		
8/1/2012	3/1/2012	FIXED SWAP	3536389	IFERC	TRNSZ4		$2.787		
8/1/2012	3/29/2012	FIXED SWAP	3545871	IFERC	MALIN		$2.457		
9/1/2012	3/29/2012	FIXED SWAP	3545872	IFERC	MALIN		$2.476		

<identified in Attachment A, Question 51, Example #1>
<identified in Attachment A, Question 51, Example #1>
<identified in Attachment A, Question 51, Example #2>
<identified in Attachment A, Question 51, Example #2>
<identified in Attachment A, Question 51, Example #3>
<identified in Attachment A, Question 51, Example #3>

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison

* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison

Note 1

Due to the fact period of the received swing different than the actual months of the strip trade executed. This causes the appearance of trades being more than 5% different from the current price for the respective day based on the simplified comparison. Below the entire strips have been put together to show how it would look when in complete form.

11/1/2012	1/30/2012	FIXED SWAP	3522740	NYMEX	NG	[redacted]	$3.242	[redacted]	0.9% Avg for the Strip Trade
12/1/2012	1/30/2012	FIXED SWAP	3522741	NYMEX	NG		$3.612		
1/1/2013	1/30/2012	FIXED SWAP	3522742	NYMEX	NG		$3.693		
2/1/2013	1/30/2012	FIXED SWAP	3522743	NYMEX	NG		$3.637		
3/1/2013	1/30/2012	FIXED SWAP	3522744	NYMEX	NG		$3.607		

<identified in Attachment A, Question 51, Example #1>
<identified in Attachment A, Question 51, Example #1>
<identified in Attachment A, Question 51, Example #1>
<identified in Attachment A, Question 51, Example #1>
<identified in Attachment A, Question 51, Example #1>

11/1/2012	2/1/2012	FIXED SWAP	3526026	IFERC	HHUB	[redacted]	$3.162	[redacted]	0.3% Avg for the Strip Trade
12/1/2012	2/1/2012	FIXED SWAP	3526027	IFERC	HHUB		$3.461		
1/1/2013	2/1/2012	FIXED SWAP	3526028	IFERC	HHUB		$3.591		
2/1/2013	2/1/2012	FIXED SWAP	3526029	IFERC	HHUB		$3.599		
3/1/2013	2/1/2012	FIXED SWAP	3526030	IFERC	HHUB		$3.585		

<identified in Attachment A, Question 51, Example #2>
<identified in Attachment A, Question 51, Example #2>
<identified in Attachment A, Question 51, Example #2>
<identified in Attachment A, Question 51, Example #2>
<identified in Attachment A, Question 51, Example #2>

11/1/2012	2/29/2012	FIXED SWAP	3534314	IFERC	HHUB	[redacted]	$3.053	[redacted]	0.1% Avg. for the Strip Trade
12/1/2012	2/29/2012	FIXED SWAP	3534315	IFERC	HHUB		$3.352		
1/1/2013	2/29/2012	FIXED SWAP	3534316	IFERC	HHUB		$3.486		
2/1/2013	2/29/2012	FIXED SWAP	3534317	IFERC	HHUB		$3.505		
3/1/2013	2/29/2012	FIXED SWAP	3534318	IFERC	HHUB		$3.467		

<identified in Attachment A, Question 51, Example #3>
<identified in Attachment A, Question 51, Example #3>
<identified in Attachment A, Question 51, Example #3>
<identified in Attachment A, Question 51, Example #3>
<identified in Attachment A, Question 51, Example #3>

130001 Hearing Exhibits - 00364

PEF-13-FL-001937

REDACTED

Question 43
2013 January - July Swap Hedges

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price	
4/1/2013	7/6/2007	FIXED SWAP	2126529	IFERC	HHUB			$6.776		4.6%
5/1/2013	7/6/2007	FIXED SWAP	2126530	IFERC	HHUB			$6.677		
6/1/2013	7/6/2007	FIXED SWAP	2126531	IFERC	HHUB			$6.755		
7/1/2013	7/6/2007	FIXED SWAP	2126532	IFERC	HHUB			$6.847		Avg for the Strip
4/1/2013	7/11/2007	FIXED SWAP	2130415	IFERC	HHUB			$6.748		
5/1/2013	7/11/2007	FIXED SWAP	2130416	IFERC	HHUB			$6.638		
6/1/2013	7/11/2007	FIXED SWAP	2130421	IFERC	HHUB			$6.727		
7/1/2013	7/11/2007	FIXED SWAP	2130422	IFERC	HHUB			$6.814		
4/1/2013	7/19/2007	FIXED SWAP	2140270	IFERC	HHUB			$6.965		
5/1/2013	7/19/2007	FIXED SWAP	2140273	IFERC	HHUB			$5.846		
6/1/2013	7/19/2007	FIXED SWAP	2140274	IFERC	HHUB			$6.925		
7/1/2013	7/19/2007	FIXED SWAP	2140353	IFERC	HHUB			$7.017		
4/1/2013	8/14/2007	FIXED SWAP	2165075	IFERC	HHUB			$7.093		
5/1/2013	8/14/2007	FIXED SWAP	2165079	IFERC	HHUB			$6.973		
6/1/2013	8/14/2007	FIXED SWAP	2165082	IFERC	HHUB			$7.045		
7/1/2013	8/14/2007	FIXED SWAP	2165083	IFERC	HHUB			$7.129		
4/1/2013	8/28/2007	FIXED SWAP	2181888	IFERC	HHUB			$8.855		
5/1/2013	8/28/2007	FIXED SWAP	2181889	IFERC	HHUB			$8.749		
6/1/2013	8/28/2007	FIXED SWAP	2181890	IFERC	HHUB			$8.822		
7/1/2013	8/28/2007	FIXED SWAP	2181891	IFERC	HHUB			$8.905		
4/1/2013	9/12/2007	FIXED SWAP	2194798	IFERC	HHUB			$7.195		
5/1/2013	9/12/2007	FIXED SWAP	2194799	IFERC	HHUB			$7.093		
6/1/2013	9/12/2007	FIXED SWAP	2194800	IFERC	HHUB			$7.161		
7/1/2013	9/12/2007	FIXED SWAP	2194801	IFERC	HHUB			$7.234		
1/1/2013	9/26/2007	FIXED SWAP	2209421	IFERC	HHUB			$8.252		0.9%
2/1/2013	9/26/2007	FIXED SWAP	2209422	IFERC	HHUB			$8.252		
3/1/2013	9/26/2007	FIXED SWAP	2209423	IFERC	HHUB			$8.003		
4/1/2013	9/26/2007	FIXED SWAP	2209424	IFERC	HHUB			$7.016		
5/1/2013	9/26/2007	FIXED SWAP	2209425	IFERC	HHUB			$6.923		
6/1/2013	9/26/2007	FIXED SWAP	2209426	IFERC	HHUB			$6.976		
7/1/2013	9/26/2007	FIXED SWAP	2209427	IFERC	HHUB			$7.035		Avg for the Strip
4/1/2013	10/3/2007	FIXED SWAP	2220225	IFERC	HHUB			$6.964		
5/1/2013	10/3/2007	FIXED SWAP	2220226	IFERC	HHUB			$6.905		
6/1/2013	10/3/2007	FIXED SWAP	2220227	IFERC	HHUB			$6.960		
7/1/2013	10/3/2007	FIXED SWAP	2220228	IFERC	HHUB			$7.018		
1/1/2013	10/19/2007	FIXED SWAP	2244150	IFERC	HHUB			$8.373		0.6%
2/1/2013	10/19/2007	FIXED SWAP	2244151	IFERC	HHUB			$8.375		
3/1/2013	10/19/2007	FIXED SWAP	2244152	IFERC	HHUB			$8.132		
4/1/2013	10/19/2007	FIXED SWAP	2244153	IFERC	HHUB			$7.223		
5/1/2013	10/19/2007	FIXED SWAP	2244154	IFERC	HHUB			$7.164		
6/1/2013	10/19/2007	FIXED SWAP	2244155	IFERC	HHUB			$7.213		
7/1/2013	10/19/2007	FIXED SWAP	2244156	IFERC	HHUB			$7.267		Avg for the Strip
1/1/2013	11/6/2007	FIXED SWAP	2262126	IFERC	HHUB			$8.424		0.8%
2/1/2013	11/6/2007	FIXED SWAP	2262127	IFERC	HHUB			$8.424		
3/1/2013	11/6/2007	FIXED SWAP	2262128	IFERC	HHUB			$8.179		
4/1/2013	11/6/2007	FIXED SWAP	2262132	IFERC	HHUB			$7.271		
5/1/2013	11/6/2007	FIXED SWAP	2262133	IFERC	HHUB			$7.217		
6/1/2013	11/6/2007	FIXED SWAP	2262135	IFERC	HHUB			$7.261		
7/1/2013	11/6/2007	FIXED SWAP	2262136	IFERC	HHUB			$7.319		Avg for the Strip
4/1/2013	12/10/2007	FIXED SWAP	2287617	IFERC	HHUB			$7.604		
5/1/2013	12/10/2007	FIXED SWAP	2287618	IFERC	HHUB			$7.554		
6/1/2013	12/10/2007	FIXED SWAP	2287619	IFERC	HHUB			$7.609		
7/1/2013	12/10/2007	FIXED SWAP	2287620	IFERC	HHUB			$7.669		

130001 Hearing Exhibits - 00365

PEF-13-FL-001938

						[redacted]		[redacted]	
4/1/2013	12/27/2007	FIXED SWAP	2298914	IFERC	HHUB		$7.953		
5/1/2013	12/27/2007	FIXED SWAP	2298915	IFERC	HHUB		$7.913		
6/1/2013	12/27/2007	FIXED SWAP	2298916	IFERC	HHUB		$7.963		
7/1/2013	12/27/2007	FIXED SWAP	2298917	IFERC	HHUB		$8.023		
4/1/2013	1/9/2008	FIXED SWAP	2304860	IFERC	HHUB		$7.760		
5/1/2013	1/9/2008	FIXED SWAP	2304861	IFERC	HHUB		$7.760		
6/1/2013	1/9/2008	FIXED SWAP	2304862	IFERC	HHUB		$7.810		
7/1/2013	1/9/2008	FIXED SWAP	2304863	IFERC	HHUB		$7.870		
4/1/2013	2/13/2008	FIXED SWAP	2334863	IFERC	HHUB		$7.949		
5/1/2013	2/13/2008	FIXED SWAP	2334864	IFERC	HHUB		$7.934		
6/1/2013	2/13/2008	FIXED SWAP	2334865	IFERC	HHUB		$7.994		
7/1/2013	2/13/2008	FIXED SWAP	2334866	IFERC	HHUB		$8.059		
1/1/2013	2/29/2008	FIXED SWAP	2348609	IFERC	HHUB		$9.587		1.2%
2/1/2013	2/29/2008	FIXED SWAP	2348610	IFERC	HHUB		$9.592		
3/1/2013	2/29/2008	FIXED SWAP	2348611	IFERC	HHUB		$9.367		
4/1/2013	2/29/2008	FIXED SWAP	2348612	IFERC	HHUB		$8.535		
5/1/2013	2/29/2008	FIXED SWAP	2348613	IFERC	HHUB		$8.520		
6/1/2013	2/29/2008	FIXED SWAP	2348614	IFERC	HHUB		$8.580		
7/1/2013	2/29/2008	FIXED SWAP	2348615	IFERC	HHUB		$8.645		Avg for the Strip
1/1/2013	4/2/2008	FIXED SWAP	2372718	IFERC	HHUB		$9.387		1.9%
2/1/2013	4/2/2008	FIXED SWAP	2372719	IFERC	HHUB		$9.387		
3/1/2013	4/2/2008	FIXED SWAP	2372722	IFERC	HHUB		$9.157		
4/1/2013	4/2/2008	FIXED SWAP	2372723	IFERC	HHUB		$8.375		
5/1/2013	4/2/2008	FIXED SWAP	2372724	IFERC	HHUB		$8.350		
6/1/2013	4/2/2008	FIXED SWAP	2372725	IFERC	HHUB		$8.415		
7/1/2013	4/2/2008	FIXED SWAP	2372726	IFERC	HHUB		$8.485		Avg for the Strip
4/1/2013	4/25/2008	FIXED SWAP	2407829	IFERC	HHUB		$8.842		
5/1/2013	4/25/2008	FIXED SWAP	2407830	IFERC	HHUB		$8.807		
6/1/2013	4/25/2008	FIXED SWAP	2407831	IFERC	HHUB		$8.872		
7/1/2013	4/25/2008	FIXED SWAP	2407832	IFERC	HHUB		$8.941		
4/1/2013	6/12/2008	FIXED SWAP	2451040	IFERC	HHUB		$10.180		
5/1/2013	6/12/2008	FIXED SWAP	2451041	IFERC	HHUB		$10.150		
6/1/2013	6/12/2008	FIXED SWAP	2451044	IFERC	HHUB		$10.225		
7/1/2013	6/12/2008	FIXED SWAP	2451045	IFERC	HHUB		$10.315		
4/1/2013	7/11/2008	FIXED SWAP	2469665	IFERC	HHUB		$9.764		
5/1/2013	7/11/2008	FIXED SWAP	2469666	IFERC	HHUB		$9.734		
6/1/2013	7/11/2008	FIXED SWAP	2469669	IFERC	HHUB		$9.814		
7/1/2013	7/11/2008	FIXED SWAP	2469670	IFERC	HHUB		$9.914		
4/1/2013	10/21/2008	FIXED SWAP	2579397	IFERC	HHUB		$7.309		
5/1/2013	10/21/2008	FIXED SWAP	2579398	IFERC	HHUB		$7.239		
6/1/2013	10/21/2008	FIXED SWAP	2579399	IFERC	HHUB		$7.324		
7/1/2013	10/21/2008	FIXED SWAP	2579400	IFERC	HHUB		$7.413		
4/1/2013	12/2/2008	FIXED SWAP	2622814	NYMEX	NG		$7.393		
5/1/2013	12/2/2008	FIXED SWAP	2622815	NYMEX	NG		$7.323		
6/1/2013	12/2/2008	FIXED SWAP	2622816	NYMEX	NG		$7.393		
7/1/2013	12/2/2008	FIXED SWAP	2622817	NYMEX	NG		$7.483		
1/1/2013	12/4/2008	FIXED SWAP	2625153	NYMEX	NG		$8.287		
2/1/2013	12/4/2008	FIXED SWAP	2625154	NYMEX	NG		$8.267		
3/1/2013	12/4/2008	FIXED SWAP	2625155	NYMEX	NG		$8.027		
1/1/2013	12/30/2008	FIXED SWAP	2640235	NYMEX	NG		$7.768		
2/1/2013	12/30/2008	FIXED SWAP	2640236	NYMEX	NG		$7.748		
3/1/2013	12/30/2008	FIXED SWAP	2640237	NYMEX	NG		$7.493		
4/1/2013	1/15/2009	FIXED SWAP	2655321	NYMEX	NG		$6.845		
5/1/2013	1/15/2009	FIXED SWAP	2655322	NYMEX	NG		$6.775		
6/1/2013	1/15/2009	FIXED SWAP	2655323	NYMEX	NG		$6.845		
7/1/2013	1/15/2009	FIXED SWAP	2655324	NYMEX	NG		$6.930		
1/1/2013	1/16/2009	FIXED SWAP	2656079	NYMEX	NG		$7.847		
2/1/2013	1/16/2009	FIXED SWAP	2656080	NYMEX	NG		$7.827		
3/1/2013	1/16/2009	FIXED SWAP	2656081	NYMEX	NG		$7.582		
4/1/2013	1/18/2010	FIXED SWAP	3161160	NYMEX	NG		$5.134		
5/1/2013	1/18/2010	FIXED SWAP	3161161	NYMEX	NG		$5.126		
6/1/2013	1/18/2010	FIXED SWAP	3161162	NYMEX	NG		$5.148		

PEF-13-FL-001939

130001 Hearing Exhibits - 00366

7/1/2013	12/16/2010	FIXED SWAP	3161165	NYMEX	NG	[redacted]	$5.193	[redacted]
4/1/2013	12/16/2010	FIXED SWAP	3172596	NYMEX	NG		$5.002	
5/1/2013	12/16/2010	FIXED SWAP	3172597	NYMEX	NG		$5.000	
6/1/2013	12/16/2010	FIXED SWAP	3172598	NYMEX	NG		$5.025	
7/1/2013	12/16/2010	FIXED SWAP	3172599	NYMEX	NG		$5.067	
1/1/2013	2/8/2011	FIXED SWAP	3202228	NYMEX	NG		$5.331	
2/1/2013	2/8/2011	FIXED SWAP	3202229	NYMEX	NG		$5.301	
3/1/2013	2/8/2011	FIXED SWAP	3202230	NYMEX	NG		$5.196	
4/1/2013	2/10/2011	FIXED SWAP	3203152	NYMEX	NG		$4.966	
5/1/2013	2/10/2011	FIXED SWAP	3203153	NYMEX	NG		$4.981	
6/1/2013	2/10/2011	FIXED SWAP	3203154	NYMEX	NG		$4.985	
7/1/2013	2/10/2011	FIXED SWAP	3203155	NYMEX	NG		$5.025	
1/1/2013	2/16/2011	FIXED SWAP	3227056	NYMEX	NG		$5.250	
2/1/2013	2/16/2011	FIXED SWAP	3227057	NYMEX	NG		$5.228	
3/1/2013	2/16/2011	FIXED SWAP	3227058	NYMEX	NG		$5.136	
1/1/2013	3/2/2011	FIXED SWAP	3213904	NYMEX	NG		$5.247	
2/1/2013	3/2/2011	FIXED SWAP	3213905	NYMEX	NG		$5.217	
3/1/2013	3/2/2011	FIXED SWAP	3213906	NYMEX	NG		$5.138	
1/1/2013	3/10/2011	FIXED SWAP	3217519	NYMEX	NG		$5.269	
2/1/2013	3/10/2011	FIXED SWAP	3217520	NYMEX	NG		$5.244	
3/1/2013	3/10/2011	FIXED SWAP	3217521	NYMEX	NG		$5.159	
4/1/2013	3/15/2011	FIXED SWAP	3220882	NYMEX	NG		$5.087	
5/1/2013	3/15/2011	FIXED SWAP	3220883	NYMEX	NG		$5.102	
6/1/2013	3/15/2011	FIXED SWAP	3220884	NYMEX	NG		$5.130	
7/1/2013	3/15/2011	FIXED SWAP	3220885	NYMEX	NG		$5.170	
1/1/2013	3/18/2011	FIXED SWAP	3222399	NYMEX	NG		$5.495	
2/1/2013	3/18/2011	FIXED SWAP	3222400	NYMEX	NG		$5.457	
3/1/2013	3/18/2011	FIXED SWAP	3222401	NYMEX	NG		$5.382	
4/1/2013	3/22/2011	FIXED SWAP	3223650	NYMEX	NG		$5.118	
5/1/2013	3/22/2011	FIXED SWAP	3223651	NYMEX	NG		$5.129	
6/1/2013	3/22/2011	FIXED SWAP	3223652	NYMEX	NG		$5.157	
7/1/2013	3/22/2011	FIXED SWAP	3223653	NYMEX	NG		$5.200	
4/1/2013	3/25/2011	FIXED SWAP	3225045	NYMEX	NG		$5.217	
5/1/2013	3/25/2011	FIXED SWAP	3225046	NYMEX	NG		$5.235	
6/1/2013	3/25/2011	FIXED SWAP	3225047	NYMEX	NG		$5.262	
7/1/2013	3/25/2011	FIXED SWAP	3225048	NYMEX	NG		$5.306	
1/1/2013	3/25/2011	FIXED SWAP	3225054	NYMEX	NG		$5.597	
2/1/2013	3/25/2011	FIXED SWAP	3225055	NYMEX	NG		$5.557	
3/1/2013	3/25/2011	FIXED SWAP	3225056	NYMEX	NG		$5.477	
1/1/2013	4/4/2011	FIXED SWAP	3231885	NYMEX	NG		$5.548	
2/1/2013	4/4/2011	FIXED SWAP	3231886	NYMEX	NG		$5.518	
3/1/2013	4/4/2011	FIXED SWAP	3231887	NYMEX	NG		$5.438	
1/1/2013	4/13/2011	FIXED SWAP	3274074	NYMEX	NG		$5.460	
2/1/2013	4/13/2011	FIXED SWAP	3274075	NYMEX	NG		$5.425	
3/1/2013	4/13/2011	FIXED SWAP	3274076	NYMEX	NG		$5.347	
4/1/2013	4/18/2011	FIXED SWAP	3277225	NYMEX	NG		$5.082	
5/1/2013	4/18/2011	FIXED SWAP	3277229	NYMEX	NG		$5.107	
6/1/2013	4/18/2011	FIXED SWAP	3277230	NYMEX	NG		$5.139	
7/1/2013	4/18/2011	FIXED SWAP	3277231	NYMEX	NG		$5.184	
4/1/2013	5/5/2011	FIXED SWAP	3295359	NYMEX	NG		$5.101	
5/1/2013	5/5/2011	FIXED SWAP	3295360	NYMEX	NG		$5.111	
6/1/2013	5/5/2011	FIXED SWAP	3295361	NYMEX	NG		$5.144	
7/1/2013	5/5/2011	FIXED SWAP	3295362	NYMEX	NG		$5.187	
1/1/2013	5/5/2011	FIXED SWAP	3295356	NYMEX	NG		$5.427	
2/1/2013	5/5/2011	FIXED SWAP	3295357	NYMEX	NG		$5.391	
3/1/2013	5/5/2011	FIXED SWAP	3295358	NYMEX	NG		$5.310	
1/1/2013	5/9/2011	FIXED SWAP	3298000	NYMEX	NG		$5.349	
2/1/2013	5/9/2011	FIXED SWAP	3298001	NYMEX	NG		$5.313	
3/1/2013	5/9/2011	FIXED SWAP	3298002	NYMEX	NG		$5.241	
4/1/2013	5/13/2011	FIXED SWAP	3301236	NYMEX	NG		$5.076	
5/1/2013	5/13/2011	FIXED SWAP	3301237	NYMEX	NG		$5.091	
6/1/2013	5/13/2011	FIXED SWAP	3301238	NYMEX	NG		$5.126	

7/1/2013	5/13/2011	FIXED SWAP	3301239	NYMEX	NG	[redacted]	$5.165	[redacted]
1/1/2013	5/13/2011	FIXED SWAP	3301233	NYMEX	NG		$5.420	
2/1/2013	5/13/2011	FIXED SWAP	3301234	NYMEX	NG		$5.383	
3/1/2013	5/13/2011	FIXED SWAP	3301235	NYMEX	NG		$5.310	
1/1/2013	5/24/2011	FIXED SWAP	3309048	NYMEX	NG		$5.470	
2/1/2013	5/24/2011	FIXED SWAP	3309049	NYMEX	NG		$5.438	
3/1/2013	5/24/2011	FIXED SWAP	3309050	NYMEX	NG		$5.357	
4/1/2013	5/25/2011	FIXED SWAP	3309825	NYMEX	NG		$5.128	
5/1/2013	5/25/2011	FIXED SWAP	3309826	NYMEX	NG		$5.144	
6/1/2013	5/25/2011	FIXED SWAP	3309827	NYMEX	NG		$5.184	
7/1/2013	5/25/2011	FIXED SWAP	3309828	NYMEX	NG		$5.222	
1/1/2013	5/27/2011	FIXED SWAP	3312394	NYMEX	NG		$5.513	
2/1/2013	5/27/2011	FIXED SWAP	3312395	NYMEX	NG		$5.476	
3/1/2013	5/27/2011	FIXED SWAP	3312396	NYMEX	NG		$5.397	
1/1/2013	6/2/2011	FIXED SWAP	3321930	NYMEX	NG		$5.592	
2/1/2013	6/2/2011	FIXED SWAP	3321931	NYMEX	NG		$5.552	
3/1/2013	6/2/2011	FIXED SWAP	3321932	NYMEX	NG		$5.470	
1/1/2013	6/9/2011	FIXED SWAP	3329693	NYMEX	NG		$5.483	
2/1/2013	6/9/2011	FIXED SWAP	3329694	NYMEX	NG		$5.445	
3/1/2013	6/9/2011	FIXED SWAP	3329695	NYMEX	NG		$5.363	
1/1/2013	6/16/2011	FIXED SWAP	3334010	NYMEX	NG		$5.377	
2/1/2013	6/16/2011	FIXED SWAP	3334011	NYMEX	NG		$5.345	
3/1/2013	6/16/2011	FIXED SWAP	3334012	NYMEX	NG		$5.270	
4/1/2013	6/17/2011	FIXED SWAP	3334607	NYMEX	NG		$4.968	
5/1/2013	6/17/2011	FIXED SWAP	3334608	NYMEX	NG		$4.983	
6/1/2013	6/17/2011	FIXED SWAP	3334609	NYMEX	NG		$5.019	
7/1/2013	6/17/2011	FIXED SWAP	3334610	NYMEX	NG		$5.053	
4/1/2013	6/28/2011	FIXED SWAP	3341169	NYMEX	NG		$4.937	
5/1/2013	6/28/2011	FIXED SWAP	3341170	NYMEX	NG		$4.943	
6/1/2013	6/28/2011	FIXED SWAP	3341171	NYMEX	NG		$4.981	
7/1/2013	6/28/2011	FIXED SWAP	3341172	NYMEX	NG		$5.021	
1/1/2013	6/28/2011	FIXED SWAP	3341165	NYMEX	NG		$5.273	
2/1/2013	6/28/2011	FIXED SWAP	3341167	NYMEX	NG		$5.243	
3/1/2013	6/28/2011	FIXED SWAP	3341168	NYMEX	NG		$5.168	
4/1/2013	7/7/2011	FIXED SWAP	3347051	NYMEX	NG		$4.881	
5/1/2013	7/7/2011	FIXED SWAP	3347052	NYMEX	NG		$4.893	
6/1/2013	7/7/2011	FIXED SWAP	3347053	NYMEX	NG		$4.927	
7/1/2013	7/7/2011	FIXED SWAP	3347054	NYMEX	NG		$4.966	
1/1/2013	7/8/2011	FIXED SWAP	3347573	NYMEX	NG		$5.267	
2/1/2013	7/8/2011	FIXED SWAP	3347574	NYMEX	NG		$5.236	
3/1/2013	7/8/2011	FIXED SWAP	3347575	NYMEX	NG		$5.160	
1/1/2013	7/12/2011	FIXED SWAP	3349580	NYMEX	NG		$5.324	
2/1/2013	7/12/2011	FIXED SWAP	3349581	NYMEX	NG		$5.292	
3/1/2013	7/12/2011	FIXED SWAP	3349582	NYMEX	NG		$5.217	
5/1/2013	7/13/2011	FIXED SWAP	3350077	IFERC	HHUB		$5.046	
6/1/2013	7/13/2011	FIXED SWAP	3350080	IFERC	HHUB		$5.082	
7/1/2013	7/13/2011	FIXED SWAP	3350081	IFERC	HHUB		$5.119	
5/1/2013	7/19/2011	FIXED SWAP	3353485	IFERC	HHUB		$5.051	
6/1/2013	7/19/2011	FIXED SWAP	3353486	IFERC	HHUB		$5.086	
7/1/2013	7/19/2011	FIXED SWAP	3353487	IFERC	HHUB		$5.124	
1/1/2013	7/19/2011	FIXED SWAP	3353527	NYMEX	NG		$5.383	
2/1/2013	7/19/2011	FIXED SWAP	3353528	NYMEX	NG		$5.350	
3/1/2013	7/19/2011	FIXED SWAP	3353529	NYMEX	NG		$5.268	
5/1/2013	7/22/2011	FIXED SWAP	3355370	IFERC	HHUB		$4.981	
6/1/2013	7/22/2011	FIXED SWAP	3355371	IFERC	HHUB		$5.016	
7/1/2013	7/22/2011	FIXED SWAP	3355372	IFERC	HHUB		$5.051	
1/1/2013	7/27/2011	FIXED SWAP	3355367	NYMEX	NG		$5.295	
2/1/2013	7/27/2011	FIXED SWAP	3355368	NYMEX	NG		$5.263	
3/1/2013	7/22/2011	FIXED SWAP	3355369	NYMEX	NG		$5.181	
1/1/2013	7/29/2011	FIXED SWAP	3367374	NYMEX	NG		$5.151	
2/1/2013	7/29/2011	FIXED SWAP	3367375	NYMEX	NG		$5.127	
3/1/2013	7/29/2011	FIXED SWAP	3367376	NYMEX	NG		$5.056	

5/1/2013	8/1/2011	FIXED SWAP	3368710	IFERC	HHUB	[redacted]	$4.941
6/1/2013	8/1/2011	FIXED SWAP	3368711	IFERC	HHUB		$4.977
7/1/2013	8/1/2011	FIXED SWAP	3368712	IFERC	HHUB		$5.013
4/1/2013	8/4/2011	FIXED SWAP	3371635	NYMEX	NG		$4.790
5/1/2013	8/4/2011	FIXED SWAP	3371636	NYMEX	NG		$4.804
6/1/2013	8/4/2011	FIXED SWAP	3371637	NYMEX	NG		$4.841
7/1/2013	8/4/2011	FIXED SWAP	3371638	NYMEX	NG		$4.878
1/1/2013	8/4/2011	FIXED SWAP	3371671	NYMEX	NG		$5.046
2/1/2013	8/4/2011	FIXED SWAP	3371672	NYMEX	NG		$5.021
3/1/2013	8/4/2011	FIXED SWAP	3371673	NYMEX	NG		$4.954
1/1/2013	8/4/2011	FIXED SWAP	3371630	NYMEX	NG		$5.046
2/1/2013	8/4/2011	FIXED SWAP	3371631	NYMEX	NG		$5.021
3/1/2013	8/4/2011	FIXED SWAP	3371632	NYMEX	NG		$4.954
5/1/2013	8/5/2011	FIXED SWAP	3372746	IFERC	HHUB		$4.833
6/1/2013	8/5/2011	FIXED SWAP	3372747	IFERC	HHUB		$4.873
7/1/2013	8/5/2011	FIXED SWAP	3372748	IFERC	HHUB		$4.913
1/1/2013	8/5/2011	FIXED SWAP	3372743	NYMEX	NG		$5.079
2/1/2013	8/5/2011	FIXED SWAP	3372744	NYMEX	NG		$5.054
3/1/2013	8/5/2011	FIXED SWAP	3372745	NYMEX	NG		$4.987
1/1/2013	8/8/2011	FIXED SWAP	3373820	NYMEX	NG		$5.076
2/1/2013	8/8/2011	FIXED SWAP	3373821	NYMEX	NG		$5.050
3/1/2013	8/8/2011	FIXED SWAP	3373822	NYMEX	NG		$4.982
5/1/2013	8/15/2011	FIXED SWAP	3377902	IFERC	HHUB		$4.880
6/1/2013	8/15/2011	FIXED SWAP	3377903	IFERC	HHUB		$4.913
7/1/2013	8/15/2011	FIXED SWAP	3377904	IFERC	HHUB		$4.950
1/1/2013	8/15/2011	FIXED SWAP	3377742	NYMEX	NG		$5.119
2/1/2013	8/15/2011	FIXED SWAP	3377743	NYMEX	NG		$5.092
3/1/2013	8/15/2011	FIXED SWAP	3377744	NYMEX	NG		$5.022
1/1/2013	8/17/2011	FIXED SWAP	3379138	NYMEX	NG		$5.074
2/1/2013	8/17/2011	FIXED SWAP	3379139	NYMEX	NG		$5.049
3/1/2013	8/17/2011	FIXED SWAP	3379140	NYMEX	NG		$4.982
1/1/2013	8/25/2011	FIXED SWAP	3383970	NYMEX	NG		$4.986
2/1/2013	8/25/2011	FIXED SWAP	3383971	NYMEX	NG		$4.960
3/1/2013	8/25/2011	FIXED SWAP	3383972	NYMEX	NG		$4.895
5/1/2013	8/26/2011	FIXED SWAP	3384407	IFERC	HHUB		$4.817
6/1/2013	8/26/2011	FIXED SWAP	3384408	IFERC	HHUB		$4.841
7/1/2013	8/26/2011	FIXED SWAP	3384409	IFERC	HHUB		$4.877
5/1/2013	8/31/2011	FIXED SWAP	3386619	IFERC	HHUB		$4.919
6/1/2013	8/31/2011	FIXED SWAP	3386620	IFERC	HHUB		$4.947
7/1/2013	8/31/2011	FIXED SWAP	3386621	IFERC	HHUB		$4.985
1/1/2013	8/31/2011	FIXED SWAP	3386626	NYMEX	NG		$5.143
2/1/2013	8/31/2011	FIXED SWAP	3386627	NYMEX	NG		$5.115
3/1/2013	8/31/2011	FIXED SWAP	3386628	NYMEX	NG		$5.045
4/1/2013	9/14/2011	FIXED SWAP	3394493	IFERC	TRNS74		$4.859
5/1/2013	9/14/2011	FIXED SWAP	3394494	IFERC	TRNS74		$4.871
6/1/2013	9/14/2011	FIXED SWAP	3394495	IFERC	TRNS74		$4.901
7/1/2013	9/14/2011	FIXED SWAP	3394496	IFERC	TRNS74		$4.939
1/1/2013	9/16/2011	FIXED SWAP	3395983	NYMEX	NG		$4.996
2/1/2013	9/16/2011	FIXED SWAP	3395984	NYMEX	NG		$4.971
3/1/2013	9/16/2011	FIXED SWAP	3395985	NYMEX	NG		$4.905
1/1/2013	10/6/2011	FIXED SWAP	3448436	NYMEX	NG		$4.818
2/1/2013	10/6/2011	FIXED SWAP	3448437	NYMEX	NG		$4.794
3/1/2013	10/6/2011	FIXED SWAP	3448438	NYMEX	NG		$4.730
1/1/2013	10/11/2011	FIXED SWAP	3456972	NYMEX	NG		$4.726
2/1/2013	10/11/2011	FIXED SWAP	3456973	NYMEX	NG		$4.703
3/1/2013	10/11/2011	FIXED SWAP	3456974	NYMEX	NG		$4.639
5/1/2013	10/14/2011	FIXED SWAP	3458817	IFERC	HHUB		$4.591
6/1/2013	10/14/2011	FIXED SWAP	3458818	IFERC	HHUB		$4.671
7/1/2013	10/14/2011	FIXED SWAP	3458819	IFERC	HHUB		$4.658
1/1/2013	10/18/2011	FIXED SWAP	3461248	NYMEX	NG		$4.663
2/1/2013	10/18/2011	FIXED SWAP	3461249	NYMEX	NG		$4.643
3/1/2013	10/18/2011	FIXED SWAP	3461250	NYMEX	NG		$4.584

1/1/2013	10/27/2011	FIXED SWAP	3472650	IFERC	HHUB	[redacted]	$4.610	[redacted]
2/1/2013	10/27/2011	FIXED SWAP	3472651	IFERC	HHUB		$4.602	
3/1/2013	10/27/2011	FIXED SWAP	3472652	IFERC	HHUB		$4.547	
5/1/2013	10/28/2011	FIXED SWAP	3473251	IFERC	HHUB		$4.556	
6/1/2013	10/28/2011	FIXED SWAP	3473252	IFERC	HHUB		$4.587	
7/1/2013	10/28/2011	FIXED SWAP	3473253	IFERC	HHUB		$4.623	
4/1/2013	11/3/2011	FIXED SWAP	3477373	NYMEX	NG		$4.432	
5/1/2013	11/3/2011	FIXED SWAP	3477374	NYMEX	NG		$4.447	
6/1/2013	11/3/2011	FIXED SWAP	3477375	NYMEX	NG		$4.477	
7/1/2013	11/3/2011	FIXED SWAP	3477376	NYMEX	NG		$4.514	
1/1/2013	11/4/2011	FIXED SWAP	3478078	NYMEX	NG		$4.584	
2/1/2013	11/4/2011	FIXED SWAP	3478079	NYMEX	NG		$4.571	
3/1/2013	11/4/2011	FIXED SWAP	3478080	NYMEX	NG		$4.519	
1/1/2013	11/7/2011	FIXED SWAP	3479524	NYMEX	NG		$4.527	
2/1/2013	11/7/2011	FIXED SWAP	3479525	NYMEX	NG		$4.510	
3/1/2013	11/7/2011	FIXED SWAP	3479526	NYMEX	NG		$4.462	
1/1/2013	11/14/2011	FIXED SWAP	3490398	NYMEX	NG		$4.353	
2/1/2013	11/14/2011	FIXED SWAP	3490399	NYMEX	NG		$4.342	
3/1/2013	11/14/2011	FIXED SWAP	3490402	NYMEX	NG		$4.297	
4/1/2013	11/14/2011	FIXED SWAP	3490468	NYMEX	NG		$4.214	
5/1/2013	11/14/2011	FIXED SWAP	3490469	NYMEX	NG		$4.229	
6/1/2013	11/14/2011	FIXED SWAP	3490470	NYMEX	NG		$4.257	
7/1/2013	11/14/2011	FIXED SWAP	3490471	NYMEX	NG		$4.296	
4/1/2013	12/5/2011	FIXED SWAP	3500329	IFERC	MAINLN		$4.127	
5/1/2013	12/5/2011	FIXED SWAP	3500330	IFERC	MAINLN		$4.150	
6/1/2013	12/5/2011	FIXED SWAP	3500331	IFERC	MAINLN		$4.181	
7/1/2013	12/5/2011	FIXED SWAP	3500332	IFERC	MAINLN		$4.224	
1/1/2013	12/12/2011	FIXED SWAP	3507916	IFERC	HHUB		$4.098	
2/1/2013	12/12/2011	FIXED SWAP	3507917	IFERC	HHUB		$4.090	
3/1/2013	12/12/2011	FIXED SWAP	3507918	IFERC	HHUB		$4.048	
4/1/2013	12/14/2011	FIXED SWAP	3503787	IFERC	MAINLN		$3.875	
5/1/2013	12/14/2011	FIXED SWAP	3503788	IFERC	MAINLN		$3.834	
6/1/2013	12/14/2011	FIXED SWAP	3503789	IFERC	MAINLN		$3.862	
7/1/2013	12/14/2011	FIXED SWAP	3503790	IFERC	MAINLN		$3.905	
1/1/2013	12/28/2011	FIXED SWAP	3508826	IFERC	HHUB		$3.950	
2/1/2013	12/28/2011	FIXED SWAP	3508829	IFERC	HHUB		$3.987	
3/1/2013	12/28/2011	FIXED SWAP	3508830	IFERC	HHUB		$3.961	
1/1/2013	1/11/2012	FIXED SWAP	3514194	IFERC	HHUB		$3.717	
2/1/2013	1/11/2012	FIXED SWAP	3514195	IFERC	HHUB		$3.715	
3/1/2013	1/11/2012	FIXED SWAP	3514196	IFERC	HHUB		$3.691	
4/1/2013	1/11/2012	FIXED SWAP	3514205	IFERC	MAINLN		$3.548	
5/1/2013	1/11/2012	FIXED SWAP	3514206	IFERC	MAINLN		$3.600	
6/1/2013	1/11/2012	FIXED SWAP	3514207	IFERC	MAINLN		$3.651	
7/1/2013	1/11/2012	FIXED SWAP	3514208	IFERC	MAINLN		$3.675	
4/1/2013	1/26/2012	FIXED SWAP	3521382	IFERC	MAINLN		$3.471	
5/1/2013	1/26/2012	FIXED SWAP	3521383	IFERC	MAINLN		$3.493	
6/1/2013	1/26/2012	FIXED SWAP	3521384	IFERC	MAINLN		$3.529	
7/1/2013	1/26/2012	FIXED SWAP	3521385	IFERC	MAINLN		$3.567	
1/1/2013	1/30/2012	FIXED SWAP	3522742	NYMEX	NG		$3.633	
2/1/2013	1/30/2012	FIXED SWAP	3522743	NYMEX	NG		$3.637	
3/1/2013	1/30/2012	FIXED SWAP	3522744	NYMEX	NG		$3.607	
1/1/2013	2/7/2012	FIXED SWAP	3526028	IFERC	HHUB		$3.591	
2/1/2013	2/7/2012	FIXED SWAP	3526029	IFERC	HHUB		$3.595	
3/1/2013	2/7/2012	FIXED SWAP	3526030	IFERC	HHUB		$3.580	
4/1/2013	2/22/2012	FIXED SWAP	3531923	IFERC	MAINLN		$3.646	
5/1/2013	2/22/2012	FIXED SWAP	3531924	IFERC	MAINLN		$3.684	
6/1/2013	2/22/2012	FIXED SWAP	3531926	IFERC	MAINLN		$3.732	
7/1/2013	2/22/2012	FIXED SWAP	3531928	IFERC	MAINLN		$3.775	
1/1/2013	2/28/2012	FIXED SWAP	3534316	IFERC	HHUB		$3.488	
2/1/2013	2/28/2012	FIXED SWAP	3534317	IFERC	HHUB		$3.505	
3/1/2013	2/28/2012	FIXED SWAP	3534318	IFERC	HHUB		$3.487	
4/1/2013	3/14/2012	FIXED SWAP	3541880	NYMEX	NG		$3.424	

PEF-13-FL-001943

130001 Hearing Exhibits - 00370

5/1/2013	3/14/2012	FIXED SWAP	3541881	NYMEX	NG	[redacted]	$3.464	[redacted]
6/1/2013	3/14/2012	FIXED SWAP	3541882	NYMEX	NG		$3.519	
7/1/2013	3/14/2012	FIXED SWAP	3541883	NYMEX	NG		$3.563	
4/1/2013	4/11/2012	FIXED SWAP	3581792	NYMEX	NG		$3.234	
5/1/2013	4/11/2012	FIXED SWAP	3581793	NYMEX	NG		$3.281	
6/1/2013	4/11/2012	FIXED SWAP	3581794	NYMEX	NG		$3.335	
7/1/2013	4/11/2012	FIXED SWAP	3581795	NYMEX	NG		$3.391	
4/1/2013	5/24/2012	FIXED SWAP	3608565	IFERC	TRNSZ4		$3.425	
5/1/2013	5/24/2012	FIXED SWAP	3608566	IFERC	TRNSZ4		$3.450	
6/1/2013	5/24/2012	FIXED SWAP	3608567	IFERC	TRNSZ4		$3.493	
7/1/2013	5/24/2012	FIXED SWAP	3608568	IFERC	TRNSZ4		$3.536	
4/1/2013	7/12/2012	FIXED SWAP	3640046	IFERC	TRNSZ4		$3.520	
5/1/2013	7/12/2012	FIXED SWAP	3640047	IFERC	TRNSZ4		$3.543	
6/1/2013	7/12/2012	FIXED SWAP	3640048	IFERC	TRNSZ4		$3.587	
7/1/2013	7/12/2012	FIXED SWAP	3640049	IFERC	TRNSZ4		$3.626	
4/1/2013	8/10/2012	FIXED SWAP	3657235	IFERC	TRNSZ4		$3.454	
5/1/2013	8/10/2012	FIXED SWAP	3657236	IFERC	TRNSZ4		$3.490	
6/1/2013	8/10/2012	FIXED SWAP	3657237	IFERC	TRNSZ4		$3.536	
7/1/2013	8/10/2012	FIXED SWAP	3657238	IFERC	TRNSZ4		$3.577	
4/1/2013	8/27/2012	FIXED SWAP	3681681	IFERC	TRNSZ4		$3.299	
5/1/2013	8/27/2012	FIXED SWAP	3681684	IFERC	TRNSZ4		$3.339	
6/1/2013	8/27/2012	FIXED SWAP	3681700	IFERC	TRNSZ4		$3.383	
7/1/2013	8/27/2012	FIXED SWAP	3681701	IFERC	TRNSZ4		$3.421	
4/1/2013	9/6/2012	FIXED SWAP	3696841	IFERC	TRNSZ4		$3.319	
5/1/2013	9/6/2012	FIXED SWAP	3696842	IFERC	TRNSZ4		$3.357	
6/1/2013	9/6/2012	FIXED SWAP	3696843	IFERC	TRNSZ4		$3.403	
7/1/2013	9/6/2012	FIXED SWAP	3696844	IFERC	TRNSZ4		$3.443	
5/1/2013	9/17/2012	FIXED SWAP	3704585	IFERC	TRNSZ4		$3.482	
6/1/2013	9/17/2012	FIXED SWAP	3704586	IFERC	TRNSZ4		$3.523	
7/1/2013	9/17/2012	FIXED SWAP	3704591	IFERC	TRNSZ4		$3.565	
5/1/2013	10/15/2012	FIXED SWAP	3743525	IFERC	TRNSZ4		$3.857	
6/1/2013	10/15/2012	FIXED SWAP	3743526	IFERC	TRNSZ4		$3.898	
7/1/2013	10/15/2012	FIXED SWAP	3743527	IFERC	TRNSZ4		$3.940	
5/1/2013	10/23/2012	FIXED SWAP	3749645	IFERC	TRNSZ4		$3.946	
6/1/2013	10/23/2012	FIXED SWAP	3749646	IFERC	TRNSZ4		$3.980	
7/1/2013	10/23/2012	FIXED SWAP	3749647	IFERC	TRNSZ4		$4.019	
5/1/2013	10/23/2012	FIXED SWAP	3749672	IFERC	TRNSZ4		$3.946	
6/1/2013	10/23/2012	FIXED SWAP	3749673	IFERC	TRNSZ4		$3.980	
7/1/2013	10/23/2012	FIXED SWAP	3749674	IFERC	TRNSZ4		$4.019	
5/1/2013	10/25/2012	FIXED SWAP	3751096	IFERC	TRNSZ4		$3.900	
6/1/2013	10/25/2012	FIXED SWAP	3751097	IFERC	TRNSZ4		$3.937	
7/1/2013	10/25/2012	FIXED SWAP	3751098	IFERC	TRNSZ4		$3.978	
4/1/2013	11/2/2012	FIXED SWAP	3762627	NYMEX	NG		$3.646	
5/1/2013	11/2/2012	FIXED SWAP	3762628	NYMEX	NG		$3.681	
6/1/2013	11/2/2012	FIXED SWAP	3762629	NYMEX	NG		$3.723	
7/1/2013	11/2/2012	FIXED SWAP	3762630	NYMEX	NG		$3.765	
4/1/2013	11/15/2012	FIXED SWAP	3778389	NYMEX	NG		$3.782	
5/1/2013	11/15/2012	FIXED SWAP	3778390	NYMEX	NG		$3.812	
6/1/2013	11/15/2012	FIXED SWAP	3778391	NYMEX	NG		$3.847	
7/1/2013	11/15/2012	FIXED SWAP	3778392	NYMEX	NG		$3.885	
4/1/2013	11/19/2012	FIXED SWAP	3780732	NYMEX	NG		$3.769	
5/1/2013	11/19/2012	FIXED SWAP	3780733	NYMEX	NG		$3.800	
6/1/2013	11/19/2012	FIXED SWAP	3780734	NYMEX	NG		$3.865	
7/1/2013	11/19/2012	FIXED SWAP	3780735	NYMEX	NG		$3.903	
4/1/2013	11/27/2012	FIXED SWAP	3785888	NYMEX	NG		$3.861	
5/1/2013	11/27/2012	FIXED SWAP	3785889	NYMEX	NG		$3.891	
6/1/2013	11/27/2012	FIXED SWAP	3785890	NYMEX	NG		$3.927	
7/1/2013	11/27/2012	FIXED SWAP	3785891	NYMEX	NG		$3.968	
4/1/2013	11/28/2012	FIXED SWAP	3786475	NYMEX	NG		$3.777	
5/1/2013	11/28/2012	FIXED SWAP	3786476	NYMEX	NG		$3.811	
6/1/2013	11/28/2012	FIXED SWAP	3786477	NYMEX	NG		$3.848	
7/1/2013	11/28/2012	FIXED SWAP	3786478	NYMEX	NG		$3.889	

4/1/2013	11/28/2012	FIXED SWAP	3788055	NYMEX	NG	[redacted]	$3.641	[redacted]
5/1/2013	11/29/2012	FIXED SWAP	3788056	NYMEX	NG		$3.679	
6/1/2013	11/29/2012	FIXED SWAP	3788057	NYMEX	NG		$3.718	
7/1/2013	11/29/2012	FIXED SWAP	3788058	NYMEX	NG		$3.761	
4/1/2013	12/4/2012	FIXED SWAP	3801713	NYMEX	NG		$3.555	
5/1/2013	12/4/2012	FIXED SWAP	3801714	NYMEX	NG		$3.596	
6/1/2013	12/4/2012	FIXED SWAP	3801715	NYMEX	NG		$3.639	
7/1/2013	12/4/2012	FIXED SWAP	3801716	NYMEX	NG		$3.682	
4/1/2013	12/7/2012	FIXED SWAP	3804745	NYMEX	NG		$3.592	
5/1/2013	12/7/2012	FIXED SWAP	3804747	NYMEX	NG		$3.633	
6/1/2013	12/7/2012	FIXED SWAP	3804750	NYMEX	NG		$3.673	
7/1/2013	12/7/2012	FIXED SWAP	3804751	NYMEX	NG		$3.713	
4/1/2013	12/10/2012	FIXED SWAP	3836227	NYMEX	NG		$3.515	
5/1/2013	12/10/2012	FIXED SWAP	3836228	NYMEX	NG		$3.559	
6/1/2013	12/10/2012	FIXED SWAP	3836229	NYMEX	NG		$3.599	
7/1/2013	12/10/2012	FIXED SWAP	3836230	NYMEX	NG		$3.642	
4/1/2013	12/13/2012	FIXED SWAP	3809620	NYMEX	NG		$3.438	
5/1/2013	12/13/2012	FIXED SWAP	3809621	NYMEX	NG		$3.482	
6/1/2013	12/13/2012	FIXED SWAP	3809622	NYMEX	NG		$3.521	
7/1/2013	12/13/2012	FIXED SWAP	3809623	NYMEX	NG		$3.563	
5/1/2013	1/9/2013	FIXED SWAP	3830732	IFERC	MAINLN		$3.256	
7/1/2013	1/9/2013	FIXED SWAP	3830733	IFERC	MAINLN		$3.320	
6/1/2013	2/7/2013	FIXED SWAP	3856040	IFERC	MAINLN		$3.426	
7/1/2013	2/7/2013	FIXED SWAP	3856041	IFERC	MAINLN		$3.488	
6/1/2013	2/11/2013	FIXED SWAP	3857445	IFERC	MAINLN		$3.430	
7/1/2013	2/11/2013	FIXED SWAP	3857446	IFERC	MAINLN		$3.491	
6/1/2013	2/14/2013	FIXED SWAP	3859785	IFERC	MAINLN		$3.315	
7/1/2013	2/14/2013	FIXED SWAP	3859786	IFERC	MAINLN		$3.377	
6/1/2013	2/22/2013	FIXED SWAP	3864907	IFERC	MAINLN		$3.414	
7/1/2013	2/22/2013	FIXED SWAP	3864908	IFERC	MAINLN		$3.473	

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison.

* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison.

Note 1

Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison. Below the entire strips have been put together to show how it would look when in complete form.

130001 Hearing Exhibits - 00372

PEF-13-FL-001945

REDACTED

Question 49
2013 January - July Storage Swap Hedges

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume/MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price
6/1/2013	2/5/2013	FIXED SWAP	3868424	FERC	FGT/Z3			$4.109	
6/1/2013	2/6/2013	FIXED SWAP	3871386	FERC	FGT/Z3			$4.046	

There were no storage hedges done between August 2012 and May 2013

* Percentage difference from trade price: Negative (-) percentages when a trade price is above the closing market price for the respective day based on the simplified comparison
* Percentage difference from trade price: Positive (+) percentages when a trade price is below the closing market price for the respective day based on the simplified comparison

Note 1
Due to the test period of the model being different than the actual months of the swaps that were executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison. Below, the same trades have been put together to show how it would look when compared to a

DEF Response to Staff 7th Rogs (Q50)
Dkt# 130001-EI

Attachments Bearing:

Bates Nos. PEF-13FL-001947 through PEF-13FL-001950

REDACTED

Question 50
2012 August - December Swap Hedges
Residual Fuel Oil

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume BBLs	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price		
8/1/2012	12/18/2008	FIXED SWAP	2634208	NYHRBH	NO61			$55.65		12.8%	identified in Attachment B, Question 51, Example #1
9/1/2012	12/18/2008	FIXED SWAP	2634210	NYHRBH	NO61			$55.49		Avg for entire strip was 13.3%	identified in Attachment B, Question 51, Example #1
10/1/2012	12/18/2008	FIXED SWAP	2634212	NYHRBH	NO61			$55.49			
11/1/2012	12/18/2008	FIXED SWAP	2634214	NYHRBH	NO61			$55.58			
12/1/2012	12/18/2008	FIXED SWAP	2634216	NYHRBH	NO61			$55.72		Avg for the Strip	
1/1/2012	7/14/2011	FIXED SWAP	3350936	NYHRBH	NO61			$104.53			
2/1/2012	7/14/2011	FIXED SWAP	3350978	NYHRBH	NO61			$104.08			
6/1/2012	12/28/2011	FIXED SWAP	3526891	NYHRBH	NO61			$96.50			
10/1/2012	12/28/2011	FIXED SWAP	3526895	NYHRBH	NO61			$96.00			
11/1/2012	6/29/2012	FIXED SWAP	3677457	NYHRBH	NO61			$88.82			
12/1/2012	6/29/2012	FIXED SWAP	3677461	NYHRBH	NO61			$88.53			
8/1/2012	7/2/2012	FIXED SWAP	3532656	NYHRBH	NO61			$92.78			

Residual Fuel Oil prices and quantities are in barrels

Question 50
2012 August - December Swap Hedges
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume BBLs	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price
8/1/2012	1/25/2011	FIXED SWAP	3196547	NYMEX	HOIND			$114.24	
9/1/2012	1/25/2011	FIXED SWAP	3196548	NYMEX	HOIND			$111.81	
8/1/2012	3/15/2011	FIXED SWAP	3270818	NYMEX	HOIND			$124.60	
9/1/2012	3/15/2011	FIXED SWAP	3270841	NYMEX	HOIND			$121.87	
10/1/2012	6/23/2011	FIXED SWAP	3336627	NYMEX	HOIND			$121.45	
11/1/2012	6/23/2011	FIXED SWAP	3336629	NYMEX	HOIND			$121.72	
12/1/2012	6/23/2011	FIXED SWAP	3336631	NYMEX	HOIND			$121.97	
10/1/2012	8/10/2011	FIXED SWAP	3375172	NYMEX	HOIND			$127.06	
11/1/2012	8/10/2011	FIXED SWAP	3375175	NYMEX	HOIND			$127.38	
12/1/2012	8/10/2011	FIXED SWAP	3375177	NYMEX	HOIND			$122.65	
1/1/2012	8/20/2012	FIXED SWAP	3673996	USGT	NO2ULS			$132.95	
12/1/2012	8/20/2012	FIXED SWAP	3673997	USGT	NO2ULS			$132.06	

Light Fuel Oil prices and quantities are traded financially in gallons

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison

Note 1
Due to the test period of the request being different than the actual months of the split deals executed this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison. Below, the entire strips have been put together to show how it would look when in complete form

1/1/2012	12/18/2008	FIXED SWAP	2634194	NYHRBH	NO61			$54.76	13.3%	identified in Attachment B, Question 51, Example #4
2/1/2012	12/18/2008	FIXED SWAP	2634195	NYHRBH	NO61			$54.84	Avg for the	identified in Attachment B, Question 51, Example #4
3/1/2012	12/18/2008	FIXED SWAP	2634196	NYHRBH	NO61			$54.97	Strip Trade	identified in Attachment B, Question 51, Example #4
4/1/2012	12/18/2008	FIXED SWAP	2634200	NYHRBH	NO61			$54.97		identified in Attachment B, Question 51, Example #4
5/1/2012	12/18/2008	FIXED SWAP	2634202	NYHRBH	NO61			$55.08		identified in Attachment B, Question 51, Example #4
6/1/2012	12/18/2008	FIXED SWAP	2634204	NYHRBH	NO61			$55.29		identified in Attachment B, Question 51, Example #4
7/1/2012	12/18/2008	FIXED SWAP	2634206	NYHRBH	NO61			$55.59		identified in Attachment B, Question 51, Example #4
8/1/2012	12/18/2008	FIXED SWAP	2634208	NYHRBH	NO61			$55.45		identified in Attachment B, Question 51, Example #4
9/1/2012	12/18/2008	FIXED SWAP	2634210	NYHRBH	NO61			$55.49		identified in Attachment B, Question 51, Example #4
10/1/2012	12/18/2008	FIXED SWAP	2634212	NYHRBH	NO61			$55.49		identified in Attachment B, Question 51, Example #4
11/1/2012	12/18/2008	FIXED SWAP	2634214	NYHRBH	NO61			$55.58		identified in Attachment B, Question 51, Example #4
12/1/2012	12/18/2008	FIXED SWAP	2634216	NYHRBH	NO61			$55.72		identified in Attachment B, Question 51, Example #4

Question 50

2012 August - December - Fuel Oil Swap Hedges - Large Light Fuel Oil

REDACTED

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume Gal	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price
8/1/2012	1/26/2011	FIXED SWAP	3196335	NYMEX	HOUND			$2.72	
9/1/2012	1/26/2011	FIXED SWAP	3196337	NYMEX	HOUND			$2.75	
8/1/2012	8/1/2011	FIXED SWAP	3176626	NYMEX	HOUND			$2.89	
9/1/2012	8/1/2011	FIXED SWAP	3176627	NYMEX	HOUND			$2.80	
10/1/2012	8/1/2011	FIXED SWAP	3176629	NYMEX	HOUND			$2.81	
11/1/2012	8/1/2011	FIXED SWAP	3176631	NYMEX	HOUND			$2.80	
12/1/2012	8/1/2011	FIXED SWAP	3176633	NYMEX	HOUND			$2.82	
8/1/2012	8/8/2011	FIXED SWAP	3362285	NYMEX	HOUND			$2.84	
9/1/2012	8/8/2011	FIXED SWAP	3362287	NYMEX	HOUND			$2.84	
10/1/2012	8/8/2011	FIXED SWAP	3362289	NYMEX	HOUND			$2.85	
11/1/2012	8/8/2011	FIXED SWAP	3362291	NYMEX	HOUND			$2.85	
12/1/2012	8/8/2011	FIXED SWAP	3362293	NYMEX	HOUND			$2.86	
8/1/2012	8/22/2011	FIXED SWAP	3454720	NYMEX	HOUND			$2.96	
9/1/2012	8/22/2011	FIXED SWAP	3454722	NYMEX	HOUND			$2.99	
10/1/2012	8/23/2012	FIXED SWAP	3674036	USGLF	NO2ULS			$3.15	
11/1/2012	8/23/2012	FIXED SWAP	3674038	USGLF	NO2ULS			$3.12	
12/1/2012	8/23/2012	FIXED SWAP	3674040	USGLF	NO2ULS			$3.10	

Light Fuel Oil prices and quantities are traded financially in gallons

Question 50

2012 August - December Fuel Oil Swap Hedges - Small Light Fuel Oil

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume Gal	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price
8/1/2012	1/26/2011	FIXED SWAP	3196341	NYMEX	HOUND			$2.72	
9/1/2012	1/26/2011	FIXED SWAP	3196343	NYMEX	HOUND			$2.75	
10/1/2012	8/21/2011	FIXED SWAP	3398154	NYMEX	HOUND			$2.86	
11/1/2012	8/21/2011	FIXED SWAP	3398156	NYMEX	HOUND			$2.86	
12/1/2012	8/21/2011	FIXED SWAP	3398158	NYMEX	HOUND			$2.90	
8/1/2012	8/8/2012	FIXED SWAP	3627778	USGLF	NO2ULS			$2.71	
9/1/2012	8/8/2012	FIXED SWAP	3627779	USGLF	NO2ULS			$2.72	

Light Fuel Oil prices and quantities are traded financially in gallons

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison

Note 1

Due to the test periods of the actuals being different than the actual months of the strip deals executed, this causes the above strip of trades to be more than 5% different from the market price for the respective day based on the simplified comparison. Below the strips have been put together in a form that should look more like

REDACTED

Question 50
2013 January - July Swap Hedges
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume BBLs	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price
1/1/2013	2/23/2012	FIXED SWAP	3532489	USGLF	NO2ULS			$137.19	
2/1/2013	2/23/2012	FIXED SWAP	3532486	USGLF	NO2ULS			$136.61	
3/1/2013	2/23/2012	FIXED SWAP	3532489	USGLF	NO2ULS			$135.02	
4/1/2013	2/23/2012	FIXED SWAP	3532491	USGLF	NO2ULS			$135.51	
5/1/2013	2/23/2012	FIXED SWAP	3532493	USGLF	NO2ULS			$134.96	
6/1/2013	2/23/2012	FIXED SWAP	3532495	USGLF	NO2ULS			$134.95	
7/1/2013	3/20/2012	FIXED SWAP	3564355	USGLF	NO2ULS			$135.79	
7/1/2013	5/7/2012	FIXED SWAP	3599952	USGLF	NO2ULS			$122.98	
7/1/2013	8/20/2012	FIXED SWAP	3674009	USGLF	NO2ULS			$126.03	
4/1/2013	10/22/2012	FIXED SWAP	3748949	USGLF	NO2ULS			$124.89	
5/1/2013	10/22/2012	FIXED SWAP	3748956	USGLF	NO2ULS			$123.94	
6/1/2013	10/22/2012	FIXED SWAP	3748958	USGLF	NO2ULS			$123.56	
7/1/2013	10/22/2012	FIXED SWAP	3748960	USGLF	NO2ULS			$123.43	
5/1/2013	4/22/2013	FIXED SWAP	3837694	USGLF	NO2ULS			$116.47	

Light Fuel Oil prices and quantities are traded financially in gallons

* Percentage difference from trade price: Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison
* Percentage difference from trade price: Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison

Note 1
Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison. Below, the strip deals have been put together to show how it would look when completed form.

130001 Hearing Exhibits - 00377

REDACTED

Question 50
2012 January July Fuel Oil Swap Hedges - Barge
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume Gal	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price
1/1/2013	1/27/2012	FIXED SWAP	3521829	USGLF	NO2ULS			$3.00	
2/1/2013	1/27/2012	FIXED SWAP	3521824	USGLF	NO2ULS			$3.00	
3/1/2013	1/27/2012	FIXED SWAP	3521939	USGLF	NO2ULS			$2.99	
4/1/2013	3/12/2012	FIXED SWAP	3540872	USGLF	NO2ULS			$3.22	
5/1/2013	3/12/2012	FIXED SWAP	3540875	USGLF	NO2ULS			$3.21	
6/1/2013	3/12/2012	FIXED SWAP	3540876	USGLF	NO2ULS			$3.20	
7/1/2013	3/26/2012	FIXED SWAP	3544388	USGLF	NO2ULS			$3.27	
8/1/2013	6/7/2012	FIXED SWAP	3599847	USGLF	NO2ULS			$2.93	
9/1/2013	9/26/2012	FIXED SWAP	3711714	USGLF	NO2ULS			$2.96	
10/1/2013	9/26/2012	FIXED SWAP	3711716	USGLF	NO2ULS			$2.93	
11/1/2013	9/26/2012	FIXED SWAP	3711714	USGLF	NO2ULS			$2.93	
12/1/2013	9/27/2012	FIXED SWAP	3714487	USGLF	NO2ULS			$2.97	
1/1/2013	10/4/2012	FIXED SWAP	3736417	USGLF	NO2ULS			$3.05	
2/1/2013	10/4/2012	FIXED SWAP	3736417	USGLF	NO2ULS			$3.00	
3/1/2013	10/4/2012	FIXED SWAP	3736419	USGLF	NO2ULS			$3.05	
4/1/2013	10/31/2012	FIXED SWAP	3761003	USGLF	NO2ULS			$3.01	
5/1/2013	10/31/2012	FIXED SWAP	3761009	USGLF	NO2ULS			$2.99	
6/1/2013	10/31/2012	FIXED SWAP	3761007	USGLF	NO2ULS			$2.98	
7/1/2013	11/13/2012	FIXED SWAP	3778782	USGLF	NO2ULS			$2.94	
8/1/2013	11/13/2012	FIXED SWAP	3778784	USGLF	NO2ULS			$2.97	
9/1/2013	11/13/2012	FIXED SWAP	3778785	USGLF	NO2ULS			$2.92	
10/1/2013	12/3/2012	FIXED SWAP	3801028	USGLF	NO2ULS			$3.03	
11/1/2013	12/3/2012	FIXED SWAP	3801027	USGLF	NO2ULS			$3.03	
12/1/2013	12/3/2012	FIXED SWAP	3801029	USGLF	NO2ULS			$3.03	
1/1/2013	12/6/2012	FIXED SWAP	3805635	USGLF	NO2ULS			$2.92	
2/1/2013	12/6/2012	FIXED SWAP	3805637	USGLF	NO2ULS			$2.93	
3/1/2013	12/6/2012	FIXED SWAP	3805639	USGLF	NO2ULS			$2.93	

Light Fuel Oil prices are quoted financially in dollars

Question 50
2012 January July Fuel Oil Swap Hedges - Rail
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Z Key	Market	Location	Volume Gal	Trade Price	Market Price on Trade Date	Percent Difference from Trade Price
1/1/2013	1/27/2012	FIXED SWAP	3521797	USGLF	NO2ULS			$3.00	
2/1/2013	1/27/2012	FIXED SWAP	3521798	USGLF	NO2ULS			$3.00	
3/1/2013	1/27/2012	FIXED SWAP	3521799	USGLF	NO2ULS			$2.99	
4/1/2013	3/12/2012	FIXED SWAP	3540866	USGLF	NO2ULS			$3.22	
5/1/2013	3/12/2012	FIXED SWAP	3540867	USGLF	NO2ULS			$3.21	
6/1/2013	3/12/2012	FIXED SWAP	3540868	USGLF	NO2ULS			$3.20	
7/1/2013	3/26/2012	FIXED SWAP	3599841	USGLF	NO2ULS			$2.93	
8/1/2013	9/26/2012	FIXED SWAP	3711704	USGLF	NO2ULS			$2.96	
9/1/2013	9/26/2012	FIXED SWAP	3711706	USGLF	NO2ULS			$2.92	
10/1/2013	9/26/2012	FIXED SWAP	3711708	USGLF	NO2ULS			$2.93	
11/1/2013	10/25/2012	FIXED SWAP	3761199	USGLF	NO2ULS			$2.93	
12/1/2013	10/25/2012	FIXED SWAP	3761203	USGLF	NO2ULS			$2.91	
1/1/2013	10/25/2012	FIXED SWAP	3761205	USGLF	NO2ULS			$2.90	
2/1/2013	11/6/2012	FIXED SWAP	3784916	USGLF	NO2ULS			$2.98	

Light Fuel Oil prices are quoted in cents per gallon

* Percentage difference from trade price - Negative numbers when a trade price is above the closing market price for the respective day based on the simplified comparison
* Percentage difference from trade price - Positive numbers when a trade price is below the closing market price for the respective day based on the simplified comparison

Note *
Due to the fact positions being different than the actual months of the strip could execution in a manner the appearance of trades being more than one different from the market price for the respective day based on the simplified comparison. Below the entire strips have been put together for a new view. Please look under Z commands form

Attachments Bearing:

Bates Nos. PEF-13FL-001951 through PEF-13FL-001952

Question #51

REDACTED

Example #1

Trade Date: January 30, 2012
Location: Nymex
Delivery Months: November 2012 through March 2013
Trade Price: [redacted]
Zkey 3522740, 3522747, 3522747, 3522743, 3522744

	Nymex Settle	Nymex High	Nymex Low	High / Low Range
Nov-12	$3.2420	$3.3230	$3.1850	$0.1380
Dec-12	$3.5120	$3.6030	$3.4550	$0.1480
Jan-13	$3.6330	$3.7580	$3.5810	$0.1770
Feb-13	$3.6370	$3.7440	$3.5870	$0.1570
Mar-13	$3.6070	$3.6800	$3.5560	$0.1240
Strip	$3.5262	$3.6216	$3.4728	$0.1488

Trade Price Difference to Strip: [redacted]
Note: See NG Swaps for 2012/2013 to identify this transaction on Question 48

Example #2

Trade Date: February 7, 2012
Location: Henry Hub IFERC
Delivery Months: November 2012 through March 2013
Trade Price: [redacted]
Zkey 3526026, 3526027, 3526028, 3526029, 3526030

	Nymex Settle	Nymex High	Nymex Low	High / Low Range
Nov-12	$3.1670	$3.2810	$3.1600	$0.1210
Dec-12	$3.4610	$3.6300	$3.4570	$0.1730
Jan-13	$3.6910	$3.7420	$3.5850	$0.1570
Feb-13	$3.5990	$3.7280	$3.5980	$0.1300
Mar-13	$3.5800	$3.7210	$3.5770	$0.1440
Strip	$3.4786	$3.6284	$3.4762	$0.1522

Trade Price Difference to Strip: [redacted]
Note: See NG Swaps for 2012/2013 to identify this transaction on Question 48.

Example #3

Trade Date: February 28, 2012
Location: Henry Hub IFERC
Delivery Months: November 2012 through March 2013
Trade Price: [redacted]
Zkey 3534314, 3534315, 3534316, 3534317, 3534318

	Nymex Settle	Nymex High	Nymex Low	High / Low Range
Nov-12	$3.0520	$3.1480	$3.0460	$0.1020
Dec-12	$3.3490	$3.4570	$3.3440	$0.1130
Jan-13	$3.4850	$3.5600	$3.4800	$0.0800
Feb-13	$3.5070	$3.5500	$3.4980	$0.0520
Mar-13	$3.4840	$3.5750	$3.4770	$0.0980
Strip	$3.3740	$3.4580	$3.3690	$0.0890

Trade Price Difference to Strip: [redacted]
Note: See NG Swaps for 2012/2013 to identify this transaction on Question 49

Question #51

REDACTED

Example #4

Trade Date: December 18, 2008
Location: NY Harbor
Delivery Months: Jan 2012 to Dec 2012
Trade Price: [redacted]
Party: 0534194/95/98/202/02/04/06/08/10/12/14/16
Explanation: Average for strip was 13.3%. See explanation for 51

	NY Harbor Trade Price	NY Harbor Market Price	Percent Difference from Trade Price
Jan-12	$63.70	$ 54.76	14.0%
Feb-12	$63.70	$ 54.84	13.9%
Mar-12	$63.70	$ 54.91	13.8%
Apr-12	$63.70	$ 54.97	13.7%
May-12	$63.70	$ 55.06	13.5%
Jun-12	$63.70	$ 55.20	13.2%
Jul-12	$63.70	$ 55.33	13.1%
Aug-12	$63.70	$ 55.45	12.9%
Sep-12	$63.70	$ 55.49	12.9%
Oct-12	$63.70	$ 55.49	12.9%
Nov-12	$63.70	$ 55.58	12.7%
Dec-12	$63.70	$ 55.72	12.5%
Strip	$63.70	$ 55.75	13.3%

	Market Quotes	Indicative Market Price	% Difference
Executed >	[redacted]	$55.25	[redacted]

DEF Response to Staff 7th Rogs (Q52)
Dkt# 130001-EI

Attachments Bearing:

Bates Nos. PEF-13FL-001953 through PEF-13FL-001955

Question 37
2017 August - December Options

REDACTED

Delivery Month	Trade Date	Instrument	Z Key	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
8/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118864	PUT	NYMEX	NG			
8/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118864	CALL	NYMEX	NG			
9/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118865	PUT	NYMEX	NG			
9/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118865	CALL	NYMEX	NG			
10/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118866	PUT	NYMEX	NG			
10/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118866	CALL	NYMEX	NG			
11/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118867	PUT	NYMEX	NG			
11/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118867	CALL	NYMEX	NG			
12/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118868	PUT	NYMEX	NG			
12/1/2012	9/17/2010	FIXED FINANCIAL OPTION	3118868	CALL	NYMEX	NG			
6/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121520	PUT	NYMEX	NG			
6/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121520	CALL	NYMEX	NG			
7/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121521	PUT	NYMEX	NG			
7/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121521	CALL	NYMEX	NG			
8/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121522	PUT	NYMEX	NG			
8/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121522	CALL	NYMEX	NG			
9/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121523	PUT	NYMEX	NG			
9/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121523	CALL	NYMEX	NG			
10/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121524	PUT	NYMEX	NG			
10/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121524	CALL	NYMEX	NG			
11/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121525	PUT	NYMEX	NG			
11/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121525	CALL	NYMEX	NG			
12/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121526	PUT	NYMEX	NG			
12/1/2012	9/27/2010	FIXED FINANCIAL OPTION	3121526	CALL	NYMEX	NG			
8/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366870	PUT	NYMEX	NG			
8/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366870	CALL	NYMEX	NG			
9/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366871	PUT	NYMEX	NG			
9/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366871	CALL	NYMEX	NG			
10/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366872	PUT	NYMEX	NG			
10/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366872	CALL	NYMEX	NG			
11/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366873	PUT	NYMEX	NG			
11/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366873	CALL	NYMEX	NG			
12/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366874	PUT	NYMEX	NG			
12/1/2012	8/1/2011	FIXED FINANCIAL OPTION	3366874	CALL	NYMEX	NG			
6/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372221	PUT	FERC	HHUB			
6/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372221	CALL	FERC	HHUB			
7/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372222	PUT	FERC	HHUB			
7/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372222	CALL	FERC	HHUB			
8/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372223	PUT	FERC	HHUB			
8/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372223	CALL	FERC	HHUB			
9/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372224	PUT	FERC	HHUB			
9/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372224	CALL	FERC	HHUB			
10/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372225	PUT	FERC	HHUB			
10/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372225	CALL	FERC	HHUB			
11/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372226	PUT	FERC	HHUB			
11/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372226	CALL	FERC	HHUB			
12/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372227	PUT	FERC	HHUB			
12/1/2012	6/6/2011	FIXED FINANCIAL OPTION	3372227	CALL	FERC	HHUB			
8/1/2012	11/16/2011	FIXED FINANCIAL OPTION	3491513	PUT	NYMEX	NG			
8/1/2012	11/16/2011	FIXED FINANCIAL OPTION	3491513	CALL	NYMEX	NG			
9/1/2012	11/16/2011	FIXED FINANCIAL OPTION	3491514	PUT	NYMEX	NG			
9/1/2012	11/16/2011	FIXED FINANCIAL OPTION	3491514	CALL	NYMEX	NG			
10/1/2012	11/16/2011	FIXED FINANCIAL OPTION	3491515	PUT	NYMEX	NG			
10/1/2012	11/16/2011	FIXED FINANCIAL OPTION	3491515	CALL	NYMEX	NG			
8/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514188	PUT	NYMEX	NG			
8/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514188	CALL	NYMEX	NG			
9/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514189	PUT	NYMEX	NG			
9/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514189	CALL	NYMEX	NG			
10/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514190	PUT	NYMEX	NG			
10/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514190	CALL	NYMEX	NG			
11/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514191	PUT	NYMEX	NG			
11/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514191	CALL	NYMEX	NG			
12/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514192	PUT	NYMEX	NG			
12/1/2012	9/1/2012	FIXED FINANCIAL OPTION	3514192	CALL	NYMEX	NG			
8/1/2012	9/17/2012	FIXED FINANCIAL OPTION	3516636	PUT	NYMEX	NG			
8/1/2012	9/17/2012	FIXED FINANCIAL OPTION	3516636	CALL	NYMEX	NG			
9/1/2012	9/17/2012	FIXED FINANCIAL OPTION	3516637	PUT	NYMEX	NG			
9/1/2012	9/17/2012	FIXED FINANCIAL OPTION	3516637	CALL	NYMEX	NG			

* No observable market quotations or quotes available for options

REDACTED

Question: 52
2013 January Daily Options

...ery Month	Trade Date	Instrument	Z Key	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
2/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272556	PUT	NYMEX	NG			
1/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272556	CALL	NYMEX	NG			
2/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272557	PUT	NYMEX	NG			
2/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272557	CALL	NYMEX	NG			
1/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272558	PUT	NYMEX	NG			
2/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272558	CALL	NYMEX	NG			
4/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272559	PUT	NYMEX	NG			
4/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272559	CALL	NYMEX	NG			
4/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272560	PUT	NYMEX	NG			
5/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272560	CALL	NYMEX	NG			
6/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272561	PUT	NYMEX	NG			
6/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272561	CALL	NYMEX	NG			
7/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272562	PUT	NYMEX	NG			
7/1/2013	4/1/2011	FIXED FINANCIAL OPTION	3272562	CALL	NYMEX	NG			
1/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329706	PUT	NYMEX	NG			
1/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329706	CALL	NYMEX	NG			
2/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329707	PUT	NYMEX	NG			
2/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329707	CALL	NYMEX	NG			
2/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329708	PUT	NYMEX	NG			
3/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329708	CALL	NYMEX	NG			
4/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329709	PUT	NYMEX	NG			
4/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329709	CALL	NYMEX	NG			
5/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329710	PUT	NYMEX	NG			
5/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329710	CALL	NYMEX	NG			
6/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329711	PUT	NYMEX	NG			
6/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329711	CALL	NYMEX	NG			
7/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329712	PUT	NYMEX	NG			
7/1/2013	6/9/2011	FIXED FINANCIAL OPTION	3329712	CALL	NYMEX	NG			
1/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369564	PUT	NYMEX	NG			
1/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369564	CALL	NYMEX	NG			
2/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369567	PUT	NYMEX	NG			
2/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369567	CALL	NYMEX	NG			
3/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369568	PUT	NYMEX	NG			
3/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369568	CALL	NYMEX	NG			
4/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369600	PUT	NYMEX	NG			
4/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369599	CALL	NYMEX	NG			
5/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369603	PUT	NYMEX	NG			
5/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369603	CALL	NYMEX	NG			
6/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369601	PUT	NYMEX	NG			
6/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369601	CALL	NYMEX	NG			
7/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369602	PUT	NYMEX	NG			
7/1/2013	8/2/2011	FIXED FINANCIAL OPTION	3369602	CALL	NYMEX	NG			
1/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455148	PUT	NYMEX	NG			
1/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455148	CALL	NYMEX	NG			
2/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455149	PUT	NYMEX	NG			
2/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455149	CALL	NYMEX	NG			
3/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455150	PUT	NYMEX	NG			
3/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455150	CALL	NYMEX	NG			
4/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455151	PUT	NYMEX	NG			
4/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455151	CALL	NYMEX	NG			
5/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455152	PUT	NYMEX	NG			
5/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455152	CALL	NYMEX	NG			
6/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455153	PUT	NYMEX	NG			
6/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455153	CALL	NYMEX	NG			
7/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455154	PUT	NYMEX	NG			
7/1/2013	10/7/2011	FIXED FINANCIAL OPTION	3455154	CALL	NYMEX	NG			
1/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488181	PUT	NYMEX	NG			
1/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488181	CALL	NYMEX	NG			
2/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488182	PUT	NYMEX	NG			
2/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488182	CALL	NYMEX	NG			
3/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488183	PUT	NYMEX	NG			
3/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488183	CALL	NYMEX	NG			
4/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488184	PUT	NYMEX	NG			
4/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488184	CALL	NYMEX	NG			
5/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488185	PUT	NYMEX	NG			
5/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488185	CALL	NYMEX	NG			
6/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488186	PUT	NYMEX	NG			
6/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488186	CALL	NYMEX	NG			
7/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488187	PUT	NYMEX	NG			
7/1/2013	11/8/2011	FIXED FINANCIAL OPTION	3488187	CALL	NYMEX	NG			
1/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491465	PUT	NYMEX	NG			
1/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491465	CALL	NYMEX	NG			
2/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491466	PUT	NYMEX	NG			
2/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491466	CALL	NYMEX	NG			
3/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491467	PUT	NYMEX	NG			
3/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491467	CALL	NYMEX	NG			
4/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491468	PUT	NYMEX	NG			
4/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491468	CALL	NYMEX	NG			
5/1/2013	11/16/2011	FIXED FINANCIAL OPTION	3491469	PUT	NYMEX	NG			

[illegible]	[illegible]	FIXED FINANCIAL OPTION	3491463	CALL	NYMEX	NG
[illegible]	[illegible]	FIXED FINANCIAL OPTION	3491470	PUT	NYMEX	NG
[illegible]	[illegible]	FIXED FINANCIAL OPTION	3491470	CALL	NYMEX	NG
[illegible]	[illegible]	FIXED FINANCIAL OPTION	3491471	PUT	NYMEX	NG
7/1/2013	11/16/2012	FIXED FINANCIAL OPTION	3491471	CALL	NYMEX	NG
7/1/2013	12/27/2011	FIXED FINANCIAL OPTION	3502035	PUT	NYMEX	NG
7/1/2013	12/28/2011	FIXED FINANCIAL OPTION	3502035	CALL	NYMEX	NG
7/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502036	PUT	NYMEX	NG
6/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502036	CALL	NYMEX	NG
5/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502037	PUT	NYMEX	NG
5/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502037	CALL	NYMEX	NG
4/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502038	PUT	NYMEX	NG
4/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502038	CALL	NYMEX	NG
3/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502039	PUT	NYMEX	NG
3/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502039	CALL	NYMEX	NG
8/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502040	PUT	NYMEX	NG
8/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502040	CALL	NYMEX	NG
7/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502041	PUT	NYMEX	NG
7/1/2013	12/29/2011	FIXED FINANCIAL OPTION	3502041	CALL	NYMEX	NG
1/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514715	PUT	NYMEX	NG
1/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514715	CALL	NYMEX	NG
2/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514716	PUT	NYMEX	NG
2/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514716	CALL	NYMEX	NG
3/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514717	PUT	NYMEX	NG
3/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514717	CALL	NYMEX	NG
4/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514718	PUT	NYMEX	NG
4/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514718	CALL	NYMEX	NG
5/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514719	PUT	NYMEX	NG
5/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514719	CALL	NYMEX	NG
6/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514720	PUT	NYMEX	NG
6/1/2013	3/12/2012	FIXED FINANCIAL OPTION	3514720	CALL	NYMEX	NG
7/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571185	PUT	FERC	TRNSZ4
7/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571185	CALL	FERC	TRNSZ4
7/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571187	PUT	FERC	TRNSZ4
7/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571187	CALL	FERC	TRNSZ4
8/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571188	PUT	FERC	TRNSZ4
8/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571188	CALL	FERC	TRNSZ4
9/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571189	PUT	FERC	TRNSZ4
9/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571189	CALL	FERC	TRNSZ4
10/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571190	PUT	FERC	TRNSZ4
10/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571190	CALL	FERC	TRNSZ4
11/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571191	PUT	FERC	TRNSZ4
11/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571191	CALL	FERC	TRNSZ4
12/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571192	PUT	FERC	TRNSZ4
12/1/2013	4/4/2012	FIXED FINANCIAL OPTION	3571192	CALL	FERC	TRNSZ4
1/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584202	PUT	FERC	TRNSZ4
1/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584202	CALL	FERC	TRNSZ4
2/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584203	PUT	FERC	TRNSZ4
2/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584203	CALL	FERC	TRNSZ4
3/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584204	PUT	FERC	TRNSZ4
3/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584204	CALL	FERC	TRNSZ4
4/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584205	PUT	FERC	TRNSZ4
4/1/2013	4/17/2012	FIXED FINANCIAL OPTION	3584205	CALL	FERC	TRNSZ4
4/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623744	PUT	FERC	TRNSZ4
4/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623744	CALL	FERC	TRNSZ4
5/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623745	PUT	FERC	TRNSZ4
5/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623745	CALL	FERC	TRNSZ4
6/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623746	PUT	FERC	TRNSZ4
6/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623746	CALL	FERC	TRNSZ4
7/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623747	PUT	FERC	TRNSZ4
7/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3623747	CALL	FERC	TRNSZ4
8/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660088	PUT	FERC	TRNSZ4
8/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660088	CALL	FERC	TRNSZ4
9/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660089	PUT	FERC	TRNSZ4
9/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660089	CALL	FERC	TRNSZ4
10/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660090	PUT	FERC	TRNSZ4
10/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660090	CALL	FERC	TRNSZ4
11/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660091	PUT	FERC	TRNSZ4
11/1/2013	6/11/2012	FIXED FINANCIAL OPTION	3660091	CALL	FERC	TRNSZ4

[redacted]

* No observed market indications or quotes available for options

72

FPUC's Responses to Staff's First Set of Interrogatories (Nos. 1-2)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 72
PARTY Florida Public Service Commission Staff[Bates
DESCRIPTION [Bates Nos. 0386-0392]

Response to Interrogatory 1

INTERROGATORY RESPONSES

FLORIDA PUBLIC UTILITIES COMPANY'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-2) DOCKET NO. 130001-EI

INTERROGATORIES

In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 and 2:

1. Please quantify and discuss all the costs and benefits under the following three scenarios. If the billing system does not have the ability to implement a particular scenario, explain why.

   a. The January first billing cycle is set for January 1 or later each year (i.e., first billing cycle for January would not begin in December of prior year);

Company Response:

With regards to the Company's current cycle billing format, all January meter reading cycles/routes regardless of the actual consumption dates are billed using the January fuel rates. Meter reading cycles have historically been billed at the rates in effect for the current billing month regardless of the occurrence of actual consumption. Meter read cycles/routes allow for meter reading spread out over the entire month; however, meter reading cycles/routes except perhaps for the last cycle of each month never contain only consumption for that calendar month. Most meter

reading cycles in January actually have consumption that occurs in the previous December calendar month; earlier cycles have more days consumed in the prior month, and so forth with each subsequent cycle having less days of consumption in December and more in January. Therefore, the billing cycles would never allow for actual monthly consumption to correspond exactly with the revenue month for which they are billed. In this scenario, you are merely reducing the number of December consumption days by one or two, and there does not seem to be any advantages that outweigh the additional cost to ensure all meter reading cycles begin in January. It would also not be practical to implement a procedure that 'resets' the January first billing cycle for January 1 since this would also entail an additional round of meter reads for December in order to capture the remainder of the December consumption that would have been normally billed in January. Consequently, additional overtime expenses would be incurred from the Company's billing group and meter reading teams in order to complete the year-end closing process for the December revenues. December also contains the most holidays, and fewest number of business days on average. On the other hand if it was possible to bill energy usage by the date of actual consumption within a calendar month, the deferral would be subsequently collected (or refunded) in future periods through the clause mechanism but would have no material impact over time to customers. It is not possible to estimate the cost to implement, but this would be more costly to the Company and ultimately to the Customers through increased payroll costs and scheduling costs, without any apparent benefit. The cost for this alternative when compared to some of the others will be less, but it would still outweigh any benefit.

Curtis D. Young

b. The effective date of new factors would be with the first billing cycle in February each year;

Company Response:

Most meter reading cycles in February actually have consumption that occurs in the previous January calendar month; earlier cycles have more days consumed in the prior month, and so forth. However, not all of the calendar year consumption will be billed under this scenario. There still exists the same issue as the current practice, but in an opposite direction. This method would not ensure that all customers are billed at the appropriate fuel factors. The January billing cycles do contain January consumption days that under this scenario would be billed inappropriately at the previous year's rates. Also if it were possible to bill energy usage by the date of actual consumption within a calendar month, the deferral would be subsequently collected (or refunded) in future periods through the clause mechanism but would have no material impact over time. There would still not be an exact matching of costs with revenues under this scenario, making it unclear for one to identify any benefit this alternative would have on customers or the Company versus the current practice.

Curtis D. Young

c. The effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (i.e., any December or November usage would be billed under prior factors).

Company Response:

The billing system and processes used by the Company do not have the ability to allow the fuel rates to be applied only to the actual per day consumption in a particular month. The meters are read once a month on the end date of each billing cycle. The Company does not have the ability to obtain consumption by date to allow for this type of application. Limitations of the billing system do not allow for two separate fuel rates for a calendar month. For this Company to embark on accommodating this scenario under its current conditions, the additional staffing and labor required to read meters and bill once a month as well as maintain and monitor its billing data to that extent would represent an impractical and inefficient utilization of time, personnel and resources in contrast to the current billing system that is in effect. On the other hand, if there exists an alternative billing system with these capabilities, the cost to the Company to install and implement one having the ability to bill as proposed under this scenario would cost the Company somewhere in excess of millions of dollars. Although once again, if it was possible to bill energy usage by the date of actual consumption within a calendar month, the deferral would be subsequently collected (or refunded) in future periods through the clause mechanism but there would be no material benefit or impact over time.

Curtis D. Young

130001 Hearing Exhibits - 00390

Response to Interrogatory 2

2. Please discuss when and how customers receive notice of the new January factors.

Company Response:

The customers receive notice of the new January factors as a memo statement on the stub portion of either 1) the bill in which the new factors go into effect or 2) the preceding bill depending on allowable time for processing. Also, all fuel docket proceedings and related information is available on the FPSC web site.

Curtis D. Young

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 4th day of March, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Curtis D. Young, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 1 and 2 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES COMPANY (NOS. 1-2) in Docket No(s). 130001-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of March, 2013.

DINA BELLECHASES MY COMMISSION EXPIRES December 19, 2015 #EE 127767 Bonded thru Notary Public Underwriters NOTARY PUBLIC STATE OF FLORIDA

Dina Bellechases

Notary Public
State of Florida, at Large

My Commission Expires:
December 19, 2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 130001-EI DATED: April 22, 2013

RESPONSES TO COMMISSION STAFF'S FIRST SET OF INTERROGATORIES (NO. 3)

The Florida Public Utilities Company ("FPUC" or "Company"), hereby submits its Responses to the Second Set of Interrogatories (No. 3) served on the Company on March 29, 2013, by the Commission Staff. The individual response follows this cover sheet.

Respectfully submitted,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706
Attorneys for Florida Public Utilities Company

Response to Interrogatory 3

INTERROGATORY RESPONSES

FLORIDA PUBLIC UTILITIES COMPANY'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NO. 3) DOCKET NO. 130001-EI

INTERROGATORIES

3. In its 2013 actual/estimated or 2014 projected testimony, will FPUC propose any new contract, new capital project, or other new cost for fuel or capacity cost recovery? If so, please list all such proposals.

Company Response:

At this time, FPUC has no proposals for any new contracts, new capital projects or other new cost for fuel or capacity cost recovery in its 2013 actual/estimated or 2014 projected testimony. It is possible that some items included in "other fuel costs" may be different from prior years.

Curtis D. Young

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH

I hereby certify that on this 18th day of April, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Curtis D. Young, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 3 from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA PUBLIC UTILITIES, INC. (NO. 3) in Docket No(s). 130001-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of April, 2013.

Bonnie L. Erdek
Notary Public
State of Florida, at Large

BONNIE L. ERDEK
MY COMMISSION # EE 089032
EXPIRES: May 1, 2015
Bonded Thru Notary Public Underwriters

My Commission Expires:
May 01, 2015

73

FPUC's Responses to Staff's Second Set of Interrogatories (No. 3)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 73
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0393-0396]

74

FPUC's Responses to Staff's Third Set of Interrogatories (Nos. 4-8)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 74
PARTY Florida Public Service Commission Staff
DESCRIPTION Withdrawn
[Bates Nos. 0397-0405]

75

FPUC's Responses to Staff's Fourth Set of Interrogatories (Nos. 9-21)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 75
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0406-0421]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 130001-EI DATED: October 17, 2013

RESPONSES TO COMMISSION STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 9 - 21) AND FIRST REQUEST FOR PRODUCTION (NOS. 1-2)

The Florida Public Utilities Company ("FPUC" or "Company"), hereby submits its Responses to the Fourth Set of Interrogatories (Nos. 9 - 21) and First Request for Production of Documents (Nos. 1-2) served on the Company on September 27, 2013, by the Commission Staff. The individual responses follow this cover sheet.

Respectfully submitted,

Beth Keating
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(850) 521-1706
Attorneys for Florida Public Utilities Company

Response to Interrogatory 9

INTERROGATORY RESPONSES

9. FPUC indicates that there is a subsidy effect in base rates favoring the Northeast Division customers. Has FPUC done a comprehensive analysis of the assets for both divisions to determine if there are subsidy effects in base rates? Please explain.

Company Response:

The Company has not conducted an analysis specifically focused on detecting any and all subsidies that may exist. The Company has, however, been aware of the subsidy effects impacting the Company's electric divisions related to transmission costs for some time and has endeavored to address that issue.

Specifically, as noted in Mr. Cutshaw's testimony, the transmission assets and the associated costs for the NW Division are currently being recovered in fuel rates from the customers in that division, because the NW division does not own transmission assets. Instead, the Company's fuel supplier for the NW Division passes transmission costs on to the NW Division through the Generation Services Agreement. Those transmission costs are, in turn, passed on to the NW Division customers through the fuel charge assessed to customers in that Division.

In contrast, the NE Division owns transmission assets. Consequently, those transmission assets and associated costs are being recovered through consolidated base rates from the customers of both divisions - thus creating an inequity whereby the transmission costs for the NE Division are allocated across both Divisions, but the transmission costs for the NW Division are recouped only from customers in the NW Division. The problem is exacerbated by the fact that the Company is implementing additional reliability measures in its NE division, resulting in additional investments in transmission assets, which has increased the transmission cost inequity between divisions. The Company is, therefore, seeking to address this issue through allocation of a portion of the transmission costs incurred for the NW Division to the NE Division through the fuel charge.

The Company first sought to address this imbalance in 2003, when the Company requested consolidation of both its base rates and fuel rates. FPUC first petitioned the Commission for a consolidation of its base rates through its rate case proceedings in Docket No. 030438-EI. Shortly thereafter, the Company also petitioned for a consolidation of its fuel rates, which was assigned Docket No. 031135-EI. The Company believed that implementation of the proposed consolidation of both its base rates and its fuel rates would address the transmission cost subsidy in a fair and equitable manner through the allocation of transmission costs for both Divisions to all Company

customers. The Company was aware that other Florida IOUs had consolidated both fuel and base rates and believed that such consolidation was also a prudent approach for FPUC.

Ultimately, the Commission approved FPUC's petition to consolidate its base rates. However, the Company's separate request to consolidate its fuel rates was denied thus creating a subsidy effect in base rates.

(Response by Curtis Young)

Response to Interrogatory 10

10. Why was the transmission assets issue raised by Mr. Cutshaw in Docket No. 130001-EI not raised by FPUC in the last two base rate proceedings?

Company Response:

Although the Company has not specifically addressed the broader disparities associated with the fact that all NE transmission assets are recovered through base rates, while NW transmission costs are not, the Company has identified this issue in the past in attempting to remedy a subset of that same issue. Specifically, in Docket No. 080001-EI, the Company sought to allocate costs associated with substation costs for its NW division through the fuel charge. In addressing this issue, Company witnesses Curtis Young and Mark Cutshaw explained that the distribution substations in the NE are owned by FPUC, while the NW is charged for use of substations owned by Gulf Power Company. The Company's witnesses further explained that the distribution facility costs are a subset of the transmission costs.

As noted in response to Interrogatory 9, FPUC first petitioned the Commission for a consolidation of its base rates through its rate case proceedings in Docket No. 030438-EI. That same year, it also petitioned for a consolidation of its conservation rates in Docket No. 030002-EG[1], as well as consolidation of its fuel rates in Docket No. 030001-EI. As noted in the Company's subsequent petition in Docket No. 031135-EI, there was no opposition to consolidation of the fuel charge in Docket No. 030001-EI[2], but the Company agreed to submit a separate petition for the consolidation request, which was then assigned Docket No. 031135-EI.[3] The Company believed consolidation would match methodologies used by most electric utilities that have standard rates for all their customers and would have eliminated the impact of cross-subsidization for both divisions.

The Company did not raise this issue again in the Company's subsequent rate case in Docket No. 070304-EI. However, at noted in response to Interrogatory 9 above, the inequity has been recently exacerbated by the fact that the Company is implementing additional reliability measures in its NE division, resulting in additional investments in transmission assets, which has increased the transmission cost inequity between the divisions. The Company is, therefore, seeking to address this issue through allocation of a portion of the transmission costs incurred for the NW Division to the NE Division through the fuel charge.
(Response by Curtis Young)

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[1] In Order No. PSC-03-1375-FOF-EG, issued in Docket No. 030002-EG, the Commission approved a stipulation allowing FPUC to consolidate its conservation rates. See also, Prehearing Order, Order No. PSC-03-1246-PHO-EG, at Section XI.
[2] See Order No. PSC-03-1461-FOF-EI.
[3] As there was no objection to consolidation in Docket No. 030001-EI, there were likewise no intervenors in the subsequent Docket No. 031135-EI.

Response to Interrogatory 11

11. Does FPUC intend to unconsolidate base rates in its next rate case proceeding? If no, why?

Company Response:

At this time, the Company has not determined what would be the most appropriate way to deal with the transmission cost issue embedded in both base and fuel rates on a long term basis. There may be multiple methods to deal with the transmission cost issue in the future; but at this time the Company believes that the fuel clause mechanism offers the most efficient method to deal with this rate issue in 2014.

One consideration is the fact that the Company no longer maintains its O & M data by division. Specifically, when the Company first asked the Commission to consolidate its base rates in Docket No. 030438-EI, the Company perceived that consolidated base rates would also provide administrative and regulatory efficiencies, enabling the Company (and the Commission) to evaluate revenue sufficiency for the services provided to customers in both divisions. Consolidation of the base rates also created certain synergies in areas such as safety, shared resources, rate proceedings and conservation to provide additional benefits. Therefore, upon consolidation, the Company ceased maintaining its O & M data by division.

(Response by Curtis Young)

Response to Interrogatory 12

12. Please refer to Mr. Cutshaw's testimony, lines 1 through 9 of page six. What is the amount of the distribution facilities charge for 2012 and the actual/estimated amount for 2013?

Company Response:

The amount of the distribution facilities charge for 2012 is $953,667.12. This amount is billed to FPUC by Southern Company Services (acting solely as an agent for Gulf Power) at $79,472.26 per month for costs associated with the distribution substation in the Northwest (NW) Division. Each month, the Company allocates half of this charge, $39,736.13, to its Northeast (NE) Division as approved by Order No. PSC-08-0824-FOF-EI.

These same charges and circumstances also apply to the actual/estimated amounts for 2013.

(Response by Curtis Young)

Response to Interrogatory 13

13. Please refer to Mr. Cutshaw's testimony and to lines 1 through 9 of page six. Please state the basis and or authority relied upon for the allocation of the Southern Company distribution facilities charge to both divisions.

Company Response:

The Commission approved this allocation by Order No. PSC- 08-0824-FOF-EI, issued in Docket No. 080001-EI, at pages 8 and 9. At page 9, the Commission noted that, "It is unfair for the NW Division to pay the total cost of its substation and also half of the substation serving the NE Division, just because the costs are collected through different mechanisms." In approving this allocation, the Commission further concluded that, ". . . whenever possible, rate differences between FPUC's two divisions which benefit one division and create subsidies for the other division shall be eliminated. We hold that in this unique instance, as described above, all FPUC customers shall contribute to both distribution substation costs in an equitable manner." Id.

As recognized in that Order, the distribution substations in the Northeast (NE) Division are owned by FPUC and their costs are recovered through base rates paid for by customers in both divisions. The corresponding distribution substation in the NW is owned by Gulf Power and FPUC pays its distribution charge as part of the purchased power agreement with these costs reflected in the fuel factors paid only by customers in the NW Division.

While Gulf has always owned the substation serving the NW Division, its cost components previously were rolled into the purchased power contract, and not separately identified. Gulf and FPUC negotiated a purchased power contract in 2007, pursuant to the Federal Energy Regulatory Commission's (FERC) Open Access Transmission Tariff (OATT). Under the purchased power contract, generation, transmission and distribution costs are separately identified.

The Commission agreed that leasing the substation from Gulf Power was more cost effective for all of FPUC's ratepayers than if FPUC were to purchase land and build its own substation and include those costs in base rates. Also, as noted above, it concluded that it would not be fair for customers in the NW Division to pay the total cost of the substation serving that division, as well as half of the substation serving the NE Division. The Commission also considered that both divisions had approximately the same number of sales and determined, therefore, that FPUC should be permitted to allocate half of the NW substations costs to the purchased power of the NE Division. This allowed all customers to contribute to the distribution charge within fuel just as all customers contribute to the substation plant related costs included in base rates.

The situation regarding transmission assets addressed in Mr. Cutshaw's testimony is virtually identical to the substation issue.

(Response by Curtis Young)

Response to Interrogatory 14

14. Does FPUC acknowledge that the Northeast Division transmission assets being in base rates results in an interdivisional inequity? If the answer to the above question is yes, does FPUC's proposal create another interdivisional inequity? Please explain.

Company Response:

The Company acknowledges that the Northeast Division transmission assets being in base rates has resulted in an interdivisional inequity and has taken steps to mitigate that inequity through its fuel clause. In its testimony for the 2009 Fuel Projection filing through Docket No. 080001-EI, FPUC requested approval to allocate a portion of the distribution substation charges incurred by the NW Division towards the NE Division fuel costs in an effort to allow all customers to contribute to the distribution charge within fuel just as all customers contribute to the substation plant related costs included in base rates. FPUC believes its proposal to allocate a portion of the Northwest Division transmission costs for fuel to the Northeast Division as a means of further mitigating the inequity in base rates and that it is the most efficient and effective means available to deal with the inequity on an interim basis.

(Response by Curtis Young)

15. If the Commission does not approve Mr. Cutshaw's recommendation, then is it FPUC contention that the base rates are discriminatory? Please explain.

Company Response:

The Company believes that, for purposes of this issue, the Company's base rates should not be considered in a vacuum. Without an adjustment to the fuel rates to address the allocation of transmission costs, an inequity does exist in the total amount paid by customers in each of the Company's electric divisions. FPUC believes its proposal to allocate a portion of the Northwest Division transmission costs for fuel to the Northeast Division as a means of further mitigating the inequity in base rates and that it is the most efficient and effective means available to deal with the overall inequity, if only on an interim basis. The Company recognizes that, at the appropriate time, it may be prudent to consider another long-term solution to this imbalance.

(Response by Curtis Young)

16. Considering solely the fuel factors for both divisions based on Mr. Cutshaw's recommendation, will those fuel factors be discriminatory? Please explain.

Company Response:

The fuel factors as filed in the current fuel clause correct for inequities existing in base rates for the transmission plant assets owned by its NE Division and gets the Company closer to more equitable rates on a consolidated base and fuel basis. Additional steps can be taken in the future to further correct any possible inequities when a more thorough and comprehensive review of rates can be made. FPUC believes its proposal to allocate a portion of the Northwest Division transmission costs for fuel to the Northeast Division as a means of further mitigating the inequity in fuel rates and that it is the most efficient and effective means available to deal with the inequity on an interim basis.

(Response by Curtis Young)

Response to Interrogatory 17

17. Please refer to Schedule C attached to the testimony of Mark Cutshaw. What is the date of this information?

Company Response:

The information provided in the Schedule C attachment is generated from the Company's 2014 forecasted budget data.

(Response by Curtis Young)

Response to Interrogatory 18

18. Please refer to page 4 of Mark Cutshaw's testimony, lines 8 through 17. Is the Northeast Division transmission plant associated with serving the division's GSLD-1 customer?

Company Response:

Yes, the Company included its GSLD1 customer data in addition to those of the other customer classes among the rate base computations within its base rate proceedings.

(Response by Curtis Young)

19. Have the costs of the Northeast Division transmission assets been allocated to large demand customers?

Company Response:

Yes, the Company included its large demand customer data in addition to those of the other customer classes among the rate base computations within its base rate proceedings.

(Response by Curtis Young)

Response to Interrogatory 20

20. For the Northwest and Northeast Divisions, please state the allocation of transmission costs to large demand customers. As part of the response to this interrogatory, please explain the allocation and show the calculations and inputs.

Company Response:

For the NW Division, $1,814,788 demand dollars are allocated to large demand customers, of which $122,504 are transmission costs. For the NE Division, $748,399 demand dollars are allocated to large demand customer, of which $135,889 are transmission costs.

The methodology for the Company's allocation of transmission costs to large demand customers is illustrated on Page 2 of 14 (NW Division) and Page 9 of 14 (NE Division) of Composite Exhibit Number CDY-3 in Docket No. 130001-EI. The allocated transmission costs are embedded in the 'Demand Dollars' of column (13).

(Response by Curtis Young)

Response to Interrogatory 21

21. Has FPUC considered a limited proceeding or other base rate proceeding to address the transmission assets of the Northeast Division? Please explain.

Company Response:

Yes, the Company is reviewing the possibility of utilizing additional mechanisms in an effort to address the inequities in the divisional base rate distribution of its transmission plant assets in the NE Division to the NW Division. However, on an interim basis, it has determined that the best means available of addressing some of the inequity is through the allocation its NW Division fuel costs, similar to the approach taken in Docket No. 080001-EI with regard to costs associated with the distribution substations.

(Response by Curtis Young)

76

Gulf's Responses to Staff's First Set of Interrogatories (Nos. 1-12)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 76
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0422-0460]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 130001-EI Date Filed: March 1, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-12)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's First Set of Interrogatories (Nos. 1-12) on the following pages.

Respectfully submitted by electronic mail the 1st day of March 1, 2013,

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In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 through 2:

1. Please quantify and discuss all the costs and benefits under the following three scenarios. If the billing system does not have the ability to implement a particular scenario, explain why.
   (a) The January first billing cycle is set for January 1 or later each year (i.e., first billing cycle for January would not begin in December of prior year);
   (b) The effective date of new factors would be with the first billing cycle in February each year;
   (c) The effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (i.e., any December or November usage would be billed under prior factors).

ANSWER:

Establishment of the meter reading schedule (billing cycle) is performed outside of the billing system (CSS). The model used to create the schedule takes into account several variables including the number of bill groups, the reading window, days in the month, holidays, weekends, etc. As a result, the first read date for a year or a month will not always fall on the first day of that period. Once created, the dates are then entered into the billing system.

For scenarios (a) and (b), there are no quantifiable costs associated with making those changes to our reading dates other than the time required to modify the current model. Making such a change would require the agreement of the other system companies that use the model for creating their read schedules. There is also an opportunity cost associated with becoming non-standard with the other operating companies as we lose many of the operational efficiencies that come with our standard processes and procedures. If scenario (b) were adopted, the fuel factors developed in the Fuel cost projection filing for the year of implementation would need to be based on February through January projected fuel costs and kWh sales.

Scenario (c) would be cost prohibitive. This scenario would require significant changes and upgrades to our existing system and infrastructure to support the ability to capture and bill ALL customers with interval data in order to measure each customer's usage through December 31st, which would be required for scenario C to work.

2. Please discuss when and how customers receive notice of the new January factors.

ANSWER:

Using 2013 as an example, information regarding the various cost recovery clause factors to be effective with the first billing cycle of January 2013 was included as an insert in customers' billings beginning with the first billing cycle in December 2012.

Interrogatory Nos. 3-12 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

3. For each type of fuel used for the power generated by the GPIF units dispatched, provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

ANSWER:

Year		Energy Input MMBtu	Power Output MWh	Annual Average Heat Rate MMBtu/MWh	Fuel Costs $
1980	Coal	62,750,813	5,819,202	10.783	$112,623,455
1980	Gas	3,182,387	261,910	12.151	$6,728,508
1990	Coal	74,702,150	7,003,292	10.667	$153,742,690
1990	Gas	218,503	5,891	37.091	$693,519
2000	Coal	114,580,411	11,163,534	10.264	$173,625,298
2000	Gas	77,817	4,346	17.905	$308,670
2010	Coal	98,165,444	9,211,903	10.656	$484,097,844
2010	Gas	0	0	0.000	N/A
2011	Coal	70,790,224	6,486,893	10.913	$344,487,156
2011	Gas	0	0	0.000	N/A
2012	Coal	45,745,758	4,132,835	11.069	$211,849,339
2012	Gas	4,131,076	352,523	11.719	$12,279,598

Data source is Schedule 21A of Gulf Power's Operating Report.

Note: Gas shown was the coal fired GPIF units

4. For each type of fuel used for the power generated by all units dispatched (including non-GPIF units), provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

ANSWER:

Year		Energy Input MMBtu	Power Output MWh	Annual Average Heat Rate MMBtu/MWh	Fuel Costs $
1980	Coal	66,594,879	6,135,902	10.853	$119,904,290
1980	Gas	4,127,959	323,753	12.750	$8,428,120
1990	Coal	80,819,921	7,522,635	10.744	$163,629,999
1990	Gas	1,036,645	56,169	18.456	$2,016,075
2000	Coal	118,462,449	11,474,382	10.324	$179,668,078
2000	Gas	2,351,239	135,596	17.340	$7,839,552
2010	Coal	99,348,127	9,302,258	10.680	$490,869,562
2010	Gas	17,660,986	2,847,102	6.203	$108,465,113
2011	Coal	71,824,302	6,562,918	10.944	$349,147,977
2011	Gas	27,299,670	3,835,998	7.117	$135,749,348
2012	Coal	45,831,749	4,134,336	11.086	$212,177,156
2012	Gas	31,312,502	4,142,479	7.559	$115,261,614

Data source is Schedule 21A of Gulf Power's Operating Report.

Note: Gas shown prior to 2010 was fired on Crist 1-3 additional coal was on Scholz 1 & 2

Interrogatory 3

Data from Schedule 21A of the Operating Report

GPIF units' fuel type

Year	Energy Input MMBTU	Power Output MWh	Annual Avg Heat Rate MMBTU/MWh
1980 Coal	62,750,813	5,819,202	10.783
1980 Gas	3,182,387	261,910	12.151
1990 Coal	74,702,150	7,003,292	10.667
1990 Gas	218,503	5,891	37.091
2000 Coal	114,580,411	11,163,534	10.264
2000 Gas	77,817	4,346	17.905
2010 Coal	98,165,444	9,211,903	10.656
2010 Gas	0	0	0.000
2011 Coal	70,790,224	6,486,893	10.913
2011 Gas	0	0	0.000
2012 Coal	45,745,758	4,132,835	11.069
2012 Gas	4,131,076	352,523	11.719

Note: Gas shown was cofired on the Coal fired GPIF units

Interrogatory 4

Data from Schedule 21A of the Operating Report

All units' fuel type

Year	Energy Input MMBTU	Power Output MWh	Annual Avg Heat Rate MMBTU/MWh
1980 Coal	66,594,879	6,135,902	10.853
1980 Gas	4,127,959	323,753	12.750
1990 Coal	80,819,921	7,522,635	10.744
1990 Gas	1,036,645	56,169	18.456
2000 Coal	118,462,449	11,474,382	10.324
2000 Gas	2,351,239	135,596	17.340
2010 Coal	99,348,127	9,302,258	10.680
2010 Gas	17,660,986	2,847,102	6.203
2011 Coal	71,824,302	6,562,918	10.944
2011 Gas	27,299,670	3,835,998	7.117
2012 Coal	45,831,749	4,134,336	11.086
2012 Gas	31,312,502	4,142,479	7.559

Note: Gas shown prior to 2010 was fired on Crist 1-3 additional coal was on Scholz 1 & 2

Staff's First Set of Interrogatories
Docket No. 130001-EI
GULF POWER COMPANY
March 1, 2013
Items 3 & 4

Fuel Cost $
$112,623,455
$6,728,508
$153,742,690
$693,519
$173,625,298
$308,670
$484,097,844
N/A
$344,487,156
N/A
$211,849,339
$12,279,598

Fuel Cost $
$119,904,290
$8,428,120
$163,629,999
$2,016,075
$179,668,078
$7,839,552
$490,869,562
$108,465,113
$349,147,977
$135,749,348
$212,177,156
$115,261,614

5. Please provide the calculations of the maximum potential GPIF incentive amount allowed per 1,000 kWh jurisdictional sales for each year since the implementation of the GPIF. As part of the response, please show the maximum allowed jurisdictional GPIF incentive dollars, jurisdictional sales, and the percentage for heat rate incentive and availability incentive respectively.

ANSWER:

See Attachment A, page 1 of 9

Interrogatory 5

Data Period	Unit	Weighting % EAF	Weighting % Heat Rate	Max. Jurisdictional GPIF Incentive $$	Jurisdictional Sales kWH	GPIF Maximum Incentive per 1,000 kWh
Oct. 1980 - Mar. 1981	Gulf	11.11	88.89	Data Not Available		
Apr. 1981 - Sept. 1981	Gulf	12.05	87.95	$479,079	2,878,539,033	$0.17
Oct. 1981 - Mar. 1982	Gulf	14.00	86.00	Data Not Available		
Apr. 1982 - Sep. 1982	Gulf	16.40	83.60	$520,268	2,857,920,000	$0.18
Oct. 1982 - Mar. 1983	Data Not Available					
Apr. 1983 - Sep. 1983	Data Not Available					
Oct. 1983 - Mar. 1984	Gulf	27.80	72.20	$586,950	2,659,518,000	$0.22
Apr. 1984 - Sep. 1984	Gulf	10.60	89.40	$612,900	3,190,849,000	$0.19
Oct. 1984 - Mar. 1985	Gulf	17.00	83.00	$657,400	2,798,387,000	$0.23
Apr. 1985 - Sep. 1985	Gulf	8.00	92.00	$677,500	3,389,117,000	$0.20
Oct. 1985 - Mar. 1986	Gulf	5.20	94.80	$723,003	3,705,760,000	$0.20
Apr. 1986 - Sep. 1986	Gulf	8.30	91.70	$709,600	2,907,630,728	$0.24
Oct. 1986 - Mar. 1987	Gulf	3.30	96.70	$669,966	3,039,487,269	$0.22
Apr. 1987 - Sep. 1987	Gulf	7.10	91.90	$678,935	3,885,374,000	$0.17
Oct. 1987 - Mar. 1988	Gulf	14.90	85.10	$636,083	3,167,647,860	$0.20
Apr. 1988 - Sep. 1988	Gulf	16.00	84.00	$690,970	3,951,708,587	$0.17
Oct. 1988 - Mar. 1989	Gulf	21.50	78.50	$702,524	3,194,939,016	$0.22
Apr. 1989 - Sep. 1989	Gulf	5.10	94.90	$707,184	4,156,926,098	$0.17
Oct 1989 - Mar. 1990	Gulf	18.70	81.20	$715,138	3,426,617,143	$0.21
Apr. 1990 - Sep. 1990	Gulf	23.60	76.50	$706,772	4,411,185,825	$0.16
Oct. 1990 - Mar. 1991	Gulf	23.20	77.00	$724,600	3,437,077,011	$0.21
Apr. 1991 - Sep. 1991	Gulf	13.10	86.80	$726,106	4,374,673,363	$0.17
Oct. 1991 - Mar. 1992	Gulf	3.40	96.60	$756,763	3,588,217,983	$0.21
Apr. 1992 - Sep. 1992	Gulf	23.10	77.00	$767,867	4,411,845,239	$0.17
Oct. 1992 - Mar. 1993	Gulf	4.60	95.50	$786,636	3,761,653,610	$0.21
Apr. 1993 - Sep. 1993	Gulf	17.50	82.50	$798,459	4,537,269,419	$0.18
Oct. 1993 - Mar. 1994	Gulf	15.00	85.00	$816,745	3,696,744,169	$0.22
Apr. 1994 - Sep. 1994	Gulf	15.80	84.30	$818,979	4,437,606,751	$0.18
Oct. 1994 - Mar. 1995	Gulf	10.90	41.00	$838,713	3,718,069,822	$0.23
Apr. 1995 - Sept. 1995	Gulf	9.70	90.30	$850,488	4,801,877,279	$0.18
Oct. 1995 - Mar. 1996	Gulf	3.30	54.20	$867,339	3,940,288,470	$0.22
Apr. 1996 - Sept. 1996	Gulf	6.60	93.30	$865,247	4,765,989,890	$0.18
Oct. 1996 - Mar. 1997	Gulf	3.20	96.60	$873,024	3,917,519,994	$0.22
Apr. 1997 - Sept. 1997	Gulf	10.40	89.60	$859,272	4,924,290,672	$0.17
Oct. 1997 - Mar. 1998	Gulf	3.90	96.10	$857,969	4,063,130,295	$0.21
Apr. 1998 - Sept. 1998	Gulf	31.30	68.90	$837,275	5,355,886,805	$0.16
Oct. 1998 - Dec. 1998	Gulf	22.90	77.10	$425,010	2,064,403,827	$0.21
Jan. 1999 - Dec. 1999	Gulf	23.00	76.90	$1,671,292	9,559,183,000	$0.17
Jan. 2000 - Dec. 2000	Gulf	26.70	73.20	$1,665,490	10,112,966,114	$0.16
Jan. 2001 - Dec. 2001	Gulf	26.10	73.90	$1,965,413	10,173,244,714	$0.19
Jan. 2002 - Dec. 2002	Gulf	33.20	66.80	$2,138,220	10,771,897,000	$0.20
Jan. 2003 - Dec. 2003	Gulf	27.50	72.60	$2,193,964	10,884,788,538	$0.20
Jan. 2004 - Dec. 2004	Gulf	24.20	75.70	$2,314,074	11,046,409,000	$0.21
Jan. 2005 - Dec. 2005	Gulf	20.40	79.50	$2,347,839	11,238,895,864	$0.21
Jan. 2006 - Dec. 2006	Gulf	18.12	81.88	$2,441,632	11,428,880,000	$0.21
Jan. 2007 - Dec. 2007	Gulf	26.51	73.49	$2,797,970	11,520,888,320	$0.24
Jan. 2008 - Dec. 2008	Gulf	18.51	81.45	$3,143,803	11,543,399,139	$0.27
Jan. 2009 - Dec. 2009	Gulf	15.73	84.26	$3,738,632	10,902,824,031	$0.34
Jan. 2010 - Dec. 2010	Gulf	9.94	90.07	$4,137,891	11,359,195,303	$0.36
Jan. 2011 - Dec. 2011	Gulf	4.19	95.81	$4,372,522	11,040,286,590	$0.40
Jan. 2012 - Dec. 2012	Gulf	8.00	92.00	$4,592,104	10,662,633,576	$0.43

Interrogatory 5

Data Period	Unit	Weighting % EAF	Weighting % Heat Rate	Max. Jurisdictional GPIF Incentive $$	Jurisdictional Sales kWH	GPIF Maximum Incentive per 1,000 kWh
Oct. 1980 - Mar. 1981	Gulf	11.11	88.89	Data Not Available		
Apr. 1981 - Sept. 1981	Gulf	12.05	87.95	$479,079	2,878,539,033	$0.17
Oct. 1981 - Mar. 1982	Gulf	14.00	86.00	Data Not Available		
Apr. 1982 - Sep. 1982	Gulf	16.40	83.60	$520,268	2,857,920,000	$0.18
Oct. 1982 - Mar. 1983	Data Not Available					
Apr. 1983 - Sep. 1983	Data Not Available					
Oct. 1983 - Mar. 1984	Gulf	27.80	72.20	$586,950	2,659,518,000	$0.22
Apr. 1984 - Sep. 1984	Gulf	10.60	89.40	$612,900	3,190,849,000	$0.19
Oct. 1984 - Mar. 1985	Gulf	17.00	83.00	$657,400	2,798,387,000	$0.23
Apr. 1985 - Sep. 1985	Gulf	8.00	92.00	$677,500	3,389,117,000	$0.20
Oct. 1985 - Mar. 1986	Gulf	5.20	94.80	$723,003	3,705,760,000	$0.20
Apr. 1986 - Sep. 1986	Gulf	8.30	91.70	$709,600	2,907,630,728	$0.24
Oct. 1986 - Mar. 1987	Gulf	3.30	96.70	$669,966	3,039,487,269	$0.22
Apr. 1987 - Sep. 1987	Gulf	7.10	91.90	$678,935	3,885,374,000	$0.17
Oct. 1987 - Mar. 1988	Gulf	14.90	85.10	$636,083	3,167,647,860	$0.20
Apr. 1988 - Sep. 1988	Gulf	16.00	84.00	$690,970	3,951,708,587	$0.17
Oct. 1988 - Mar. 1989	Gulf	21.50	78.50	$702,524	3,194,939,016	$0.22
Apr. 1989 - Sep. 1989	Gulf	5.10	94.90	$707,184	4,156,926,098	$0.17
Oct 1989 - Mar. 1990	Gulf	18.70	81.20	$715,138	3,426,617,143	$0.21
Apr. 1990 - Sep. 1990	Gulf	23.60	76.50	$706,772	4,411,185,825	$0.16
Oct. 1990 - Mar. 1991	Gulf	23.20	77.00	$724,600	3,437,077,011	$0.21
Apr. 1991 - Sep. 1991	Gulf	13.10	86.80	$726,106	4,374,673,363	$0.17
Oct. 1991 - Mar. 1992	Gulf	3.40	96.60	$756,763	3,588,217,983	$0.21
Apr. 1992 - Sep. 1992	Gulf	23.10	77.00	$767,867	4,411,845,239	$0.17
Oct. 1992 - Mar. 1993	Gulf	4.60	95.50	$786,636	3,761,653,610	$0.21
Apr. 1993 - Sep. 1993	Gulf	17.50	82.50	$798,459	4,537,269,419	$0.18
Oct. 1993 - Mar. 1994	Gulf	15.00	85.00	$816,745	3,696,744,169	$0.22
Apr. 1994 - Sep. 1994	Gulf	15.80	84.30	$818,979	4,437,606,751	$0.18
Oct. 1994 - Mar. 1995	Gulf	10.90	41.00	$838,713	3,718,069,822	$0.23
Apr. 1995 - Sept. 1995	Gulf	9.70	90.30	$850,488	4,801,877,279	$0.18
Oct. 1995 - Mar. 1996	Gulf	3.30	54.20	$867,339	3,940,288,470	$0.22
Apr. 1996 - Sept. 1996	Gulf	6.60	93.30	$865,247	4,765,989,890	$0.18
Oct. 1996 - Mar. 1997	Gulf	3.20	96.60	$873,024	3,917,519,994	$0.22
Apr. 1997 - Sept. 1997	Gulf	10.40	89.60	$859,272	4,924,290,672	$0.17
Oct. 1997 - Mar. 1998	Gulf	3.90	96.10	$857,969	4,063,130,295	$0.21
Apr. 1998 - Sept. 1998	Gulf	31.30	68.90	$837,275	5,355,886,805	$0.16
Oct. 1998 - Dec. 1998	Gulf	22.90	77.10	$425,010	2,064,403,827	$0.21
Jan. 1999 - Dec. 1999	Gulf	23.00	76.90	$1,671,292	9,559,183,000	$0.17
Jan. 2000 - Dec. 2000	Gulf	26.70	73.20	$1,665,490	10,112,966,114	$0.16
Jan. 2001 - Dec. 2001	Gulf	26.10	73.90	$1,965,413	10,173,244,714	$0.19
Jan. 2002 - Dec. 2002	Gulf	33.20	66.80	$2,138,220	10,771,897,000	$0.20
Jan. 2003 - Dec. 2003	Gulf	27.50	72.60	$2,193,964	10,884,788,538	$0.20
Jan. 2004 - Dec. 2004	Gulf	24.20	75.70	$2,314,074	11,046,409,000	$0.21
Jan. 2005 - Dec. 2005	Gulf	20.40	79.50	$2,347,839	11,238,895,864	$0.21
Jan. 2006 - Dec. 2006	Gulf	18.12	81.88	$2,441,632	11,428,880,000	$0.21
Jan. 2007 - Dec. 2007	Gulf	26.51	73.49	$2,797,970	11,520,888,320	$0.24
Jan. 2008 - Dec. 2008	Gulf	18.51	81.45	$3,143,803	11,543,399,139	$0.27
Jan. 2009 - Dec. 2009	Gulf	15.73	84.26	$3,738,632	10,902,824,031	$0.34
Jan. 2010 - Dec. 2010	Gulf	9.94	90.07	$4,137,891	11,359,195,303	$0.36
Jan. 2011 - Dec. 2011	Gulf	4.19	95.81	$4,372,522	11,040,286,590	$0.40
Jan. 2012 - Dec. 2012	Gulf	8.00	92.00	$4,592,104	10,662,633,576	$0.43

6. Please describe the various factors that could impact the efficient use of capital and over the long term, rates paid by customers. As part of the response, please provide the fuel and base rates breakdown for 1,000 kWh residential usage, the authorized ROE used to set base rates, the net energy for load, net MWh purchased power, net MWh generation, and T&D loss, for 1980, 1990, 2000, 2010, 2011, and 2012.

ANSWER:

Gulf strives to manage its financial resources in a manner that optimizes the performance and reliability of its generating units. In turn, this results in lower costs to produce electricity over the long term which translates to lower rates paid by customers. For further details, please refer to the response to interrogatory 11(e).

	Dec-80	Dec-90	Dec-00	Dec-10	Dec-11	Dec-12
Base Charge	$ 5.00	$ 8.00	$ 8.07	$ 10.00	$ 10.89	$ 15.00
Energy Charge	53.68	34.87	34.13	39.30	42.79	42.65
Environmental	-	-	1.23	13.91	13.43	12.94
Purchased Power Capacity	-	-	1.62	5.02	4.76	3.78
Conservation	-	0.13	0.38	1.08	0.80	2.56
Subtotal	$ 58.68	$ 43.00	$ 45.43	$ 69.31	$ 72.67	$ 76.93
Fuel	9.65	21.94	19.78	53.71	51.31	36.76
Gross Receipts	-	0.32	0.67	3.16	3.18	2.92
Total	$ 68.33	$ 65.26	$ 65.88	$ 126.18	$ 127.16	$ 116.61
Authorized ROE	13.50%	12.05%	11.50%	12.00%	12.00%	12.00%
Net Energy for load (MWh)	6,105,410	8,595,269	11,094,096	12,496,074	12,070,631	11,584,361
Net Generation (MWh)	6,150,197	8,104,950	12,865,732	12,211,483	10,507,488	8,390,935
T&D loss (MWh)	430,478	524,871	607,911	724,181	642,539	576,567

7. Please provide the projected GPIF heat rate target (Btus per kWh) and the projected MWh net generation of each GPIF unit for the years 2000 through 2012.

ANSWER:

See Attachment A, page 2 of 9

Interrogatory 7

		Heat Rate	
		Target	Projected MWh
Jan. 2000 - Dec. 2000	Crist 6	10,629	1,774,910
	Crist 7	10,236	2,947,160
	Smith 1	10,332	943,250
	Smith 2	10,137	1,233,310
	Daniel 1	10,237	2,736,910
	Daniel 2	10,105	2,803,650
Jan. 2001 - Dec. 2001	Crist 6	10,502	1,675,910
	Crist 7	10,184	3,030,460
	Smith 1	10,113	1,173,530
	Smith 2	10,058	1,307,900
	Daniel 1	10,075	2,975,360
	Daniel 2	9,872	2,982,100
Jan. 2002 - Dec. 2002	Crist 4	10,499	453,323
	Crist 6	10,546	1,675,910
	Crist 7	10,196	3,030,460
	Smith 1	10,054	1,173,530
	Smith 2	10,050	1,307,900
	Daniel 1	10,191	2,975,360
	Daniel 2	9,906	2,975,360
Jan. 2003 - Dec. 2003	Crist 4	10,591	483,726
	Crist 5	10,418	506,898
	Crist 6	10,501	1,853,509
	Crist 7	10,150	3,224,172
	Smith 1	10,029	1,216,856
	Smith 2	10,113	1,069,070
	Daniel 1	10,042	2,970,353
	Daniel 2	9,789	3,609,226
Jan. 2004 - Dec. 2004	Crist 4	10,388	630,652
	Crist 5	10,232	626,811
	Crist 6	10,501	2,223,250
	Crist 7	10,223	2,912,814
	Smith 1	10,114	1,227,831
	Smith 2	10,024	1,310,255
	Daniel 1	9,994	2,924,542
	Daniel 2	9,828	3,474,714
Jan. 2005 - Dec. 2005	Crist 4	10,610	570,302
	Crist 5	10,548	560,688
	Crist 6	10,416	1,588,425
	Crist 7	10,340	2,493,655
	Smith 1	10,273	1,061,347
	Smith 2	10,213	981,207
	Daniel 1	9,953	3,514,424
	Daniel 2	9,742	3,934,941
Jan. 2006 - Dec. 2006	Crist 4	10,493	582,217
	Crist 5	10,375	638,969
	Crist 6	10,171	2,364,602
	Crist 7	10,268	3,070,001
	Smith 1	10,176	1,384,877
	Smith 2	10,222	1,383,431
	Daniel 1	10,181	4,205,935
	Daniel 2	10,027	3,660,598

		Heat Rate	
		Target	Projected MWh
Jan. 2007 - Dec. 2007	Crist 4	10,545	665,524
	Crist 5	10,422	675,500
	Crist 6	10,258	2,241,263
	Crist 7	10,225	3,474,952
	Smith 1	10,259	1,112,857
	Smith 2	10,328	1,519,990
	Daniel 1	10,046	3,671,923
	Daniel 2	9,834	4,192,446
Jan. 2008 - Dec. 2008	Crist 4	10,696	509,903
	Crist 5	10,552	575,939
	Crist 6	10,365	2,081,741
	Crist 7	10,375	3,329,525
	Smith 1	10,238	1,327,047
	Smith 2	10,314	1,356,841
	Daniel 1	10,132	3,961,005
	Daniel 2	10,016	3,345,196
Jan. 2009 - Dec. 2009	Crist 4	10,810	592,707
	Crist 5	10,594	598,374
	Crist 6	10,530	1,893,634
	Crist 7	10,496	2,711,574
	Smith 1	10,310	1,085,372
	Smith 2	10,349	1,400,740
	Daniel 1	10,096	3,522,290
	Daniel 2	9,870	3,945,771
Jan. 2010 - Dec. 2010	Crist 4	10,837	502,347
	Crist 5	10,777	534,679
	Crist 6	10,910	1,689,872
	Crist 7	10,656	3,246,260
	Smith 1	10,300	1,176,913
	Smith 2	10,345	1,203,505
	Daniel 1	10,415	2,614,866
	Daniel 2	10,231	3,057,307
Jan. 2011 - Dec. 2011	Crist 4	11,038	508,891
	Crist 5	11,135	398,369
	Crist 6	11,121	1,247,399
	Crist 7	10,650	2,801,834
	Smith 1	10,457	951,849
	Smith 2	10,426	1,073,346
	Daniel 1	10,518	2,915,211
	Daniel 2	10,417	2,366,193
Jan. 2012 - Dec. 2012	Crist 4	11,479	450,888
	Crist 5	11,471	430,316
	Crist 6	11,457	1,127,657
	Crist 7	10,683	2,382,504
	Smith 1	10,628	913,197
	Smith 2	10,533	873,392
	Daniel 1	10,703	2,154,601
	Daniel 2	10,630	2,299,368

Interrogatory 7

		Heat Rate	
		Target	Projected MWh
Jan. 2000 - Dec. 2000	Crist 6	10,629	1,774,910
	Crist 7	10,236	2,947,160
	Smith 1	10,332	943,250
	Smith 2	10,137	1,233,310
	Daniel 1	10,237	2,736,910
	Daniel 2	10,105	2,803,650
Jan. 2001 - Dec. 2001	Crist 6	10,502	1,675,910
	Crist 7	10,184	3,030,460
	Smith 1	10,113	1,173,530
	Smith 2	10,058	1,307,900
	Daniel 1	10,075	2,975,360
	Daniel 2	9,872	2,982,100
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	Crist 6	10,546	1,675,910
	Crist 7	10,196	3,030,460
	Smith 1	10,054	1,173,530
	Smith 2	10,050	1,307,900
	Daniel 1	10,191	2,975,360
	Daniel 2	9,906	2,975,360
Jan. 2003 - Dec. 2003	Crist 4	10,591	483,726
	Crist 5	10,418	506,898
	Crist 6	10,501	1,853,509
	Crist 7	10,150	3,224,172
	Smith 1	10,029	1,216,856
	Smith 2	10,113	1,069,070
	Daniel 1	10,042	2,970,353
	Daniel 2	9,789	3,609,226
Jan. 2004 - Dec. 2004	Crist 4	10,388	630,652
	Crist 5	10,232	626,811
	Crist 6	10,501	2,223,250
	Crist 7	10,223	2,912,814
	Smith 1	10,114	1,227,831
	Smith 2	10,024	1,310,255
	Daniel 1	9,994	2,924,542
	Daniel 2	9,828	3,474,714
Jan. 2005 - Dec. 2005	Crist 4	10,610	570,302
	Crist 5	10,548	560,688
	Crist 6	10,416	1,588,425
	Crist 7	10,340	2,493,655
	Smith 1	10,273	1,061,347
	Smith 2	10,213	981,207
	Daniel 1	9,953	3,514,424
	Daniel 2	9,742	3,934,941
Jan. 2006 - Dec. 2006	Crist 4	10,493	582,217
	Crist 5	10,375	638,969
	Crist 6	10,171	2,364,602
	Crist 7	10,268	3,070,001
	Smith 1	10,176	1,384,877
	Smith 2	10,222	1,383,431
	Daniel 1	10,181	4,205,935
	Daniel 2	10,027	3,660,598

		Heat Rate	
		Target	Projected MWh
Jan. 2007 - Dec. 2007	Crist 4	10,545	665,524
	Crist 5	10,422	675,500
	Crist 6	10,258	2,241,263
	Crist 7	10,225	3,474,952
	Smith 1	10,259	1,112,857
	Smith 2	10,328	1,519,990
	Daniel 1	10,046	3,671,923
	Daniel 2	9,834	4,192,446
Jan. 2008 - Dec. 2008	Crist 4	10,696	509,903
	Crist 5	10,552	575,939
	Crist 6	10,365	2,081,741
	Crist 7	10,375	3,329,525
	Smith 1	10,238	1,327,047
	Smith 2	10,314	1,356,841
	Daniel 1	10,132	3,961,005
	Daniel 2	10,016	3,345,196
Jan. 2009 - Dec. 2009	Crist 4	10,810	592,707
	Crist 5	10,594	598,374
	Crist 6	10,530	1,893,634
	Crist 7	10,496	2,711,574
	Smith 1	10,310	1,085,372
	Smith 2	10,349	1,400,740
	Daniel 1	10,096	3,522,290
	Daniel 2	9,870	3,945,771
Jan. 2010 - Dec. 2010	Crist 4	10,837	502,347
	Crist 5	10,777	534,679
	Crist 6	10,910	1,689,872
	Crist 7	10,656	3,246,260
	Smith 1	10,300	1,176,913
	Smith 2	10,345	1,203,505
	Daniel 1	10,415	2,614,866
	Daniel 2	10,231	3,057,307
Jan. 2011 - Dec. 2011	Crist 4	11,038	508,891
	Crist 5	11,135	398,369
	Crist 6	11,121	1,247,399
	Crist 7	10,650	2,801,834
	Smith 1	10,457	951,849
	Smith 2	10,426	1,073,346
	Daniel 1	10,518	2,915,211
	Daniel 2	10,417	2,366,193
Jan. 2012 - Dec. 2012	Crist 4	11,479	450,888
	Crist 5	11,471	430,316
	Crist 6	11,457	1,127,657
	Crist 7	10,683	2,382,504
	Smith 1	10,628	913,197
	Smith 2	10,533	873,392
	Daniel 1	10,703	2,154,601
	Daniel 2	10,630	2,299,368

8. Please provide the actual heat rate performance (Btus per kWh) and the actual MWh net generation of each GPIF unit for the years 2000 through 2012.

ANSWER:

See Attachment A, page 3 of 9

Interrogatory 8

		Heat Rate	
		Actual	Actual MWh
Jan. 2000 - Dec. 2000	Crist 6	10,527	1,611,616
	Crist 7	10,250	2,883,831
	Smith 1	10,079	1,207,534
	Smith 2	10,103	1,351,951
	Daniel 1	10,224	3,218,888
	Daniel 2	10,057	3,113,517
Jan. 2001 - Dec. 2001	Crist 6	10,996	1,498,344
	Crist 7	10,411	2,154,550
	Smith 1	10,129	1,124,207
	Smith 2	10,069	1,194,135
	Daniel 1	10,228	2,823,883
	Daniel 2	10,079	3,356,159
Jan. 2002 - Dec. 2002	Crist 4	11,351	386,953
	Crist 6	10,887	1,310,655
	Crist 7	10,388	2,498,708
	Smith 1	10,244	1,035,214
	Smith 2	10,409	733,260
	Daniel 1	10,095	3,182,817
	Daniel 2	10,036	2,578,411
Jan. 2003 - Dec. 2003	Crist 4	10,617	531,291
	Crist 5	10,621	508,220
	Crist 6	10,358	2,046,711
	Crist 7	10,287	3,337,257
	Smith 1	10,384	927,042
	Smith 2	10,191	927,793
	Daniel 1	9,839	2,761,190
	Daniel 2	9,781	3,282,470
Jan. 2004 - Dec. 2004	Crist 4	10,542	590,072
	Crist 5	10,629	587,904
	Crist 6	10,229	1,739,530
	Crist 7	10,365	2,558,568
	Smith 1	10,202	1,171,957
	Smith 2	10,353	1,327,414
	Daniel 1	10,066	3,169,684
	Daniel 2	9,833	3,937,610
Jan. 2005 - Dec. 2005	Crist 4	10,731	559,832
	Crist 5	10,659	538,897
	Crist 6	10,462	1,817,214
	Crist 7	10,722	2,107,672
	Smith 1	10,321	1,210,604
	Smith 2	10,336	1,158,713
	Daniel 1	10,189	3,381,992
	Daniel 2	10,154	3,685,619
Jan. 2006 - Dec. 2006	Crist 4	10,827	537,501
	Crist 5	10,741	536,930
	Crist 6	10,435	1,873,119
	Crist 7	10,487	3,344,607
	Smith 1	10,286	1,246,653
	Smith 2	10,346	1,388,830
	Daniel 1	10,109	4,095,727
	Daniel 2	10,093	3,316,959

		Heat Rate	
		Actual	Actual MWh
Jan. 2007 - Dec. 2007	Crist 4	11,004	547,538
	Crist 5	10,750	549,455
	Crist 6	10,701	2,045,960
	Crist 7	10,665	3,224,820
	Smith 1	10,255	974,625
	Smith 2	10,314	1,408,025
	Daniel 1	10,182	3,358,074
	Daniel 2	10,008	3,654,136
Jan. 2008 - Dec. 2008	Crist 4	10,762	337,807
	Crist 5	10,679	442,784
	Crist 6	10,912	1,390,244
	Crist 7	10,683	3,065,788
	Smith 1	10,285	1,098,164
	Smith 2	10,460	1,269,704
	Daniel 1	10,202	3,318,700
	Daniel 2	9,923	3,118,773
Jan. 2009 - Dec. 2009	Crist 4	10,816	222,242
	Crist 5	11,177	380,519
	Crist 6	11,205	937,988
	Crist 7	11,018	1,801,763
	Smith 1	10,689	516,735
	Smith 2	10,353	937,338
	Daniel 1	10,499	2,510,257
	Daniel 2	10,341	2,500,829
Jan. 2010 - Dec. 2010	Crist 4	11,679	247,278
	Crist 5	11,368	443,048
	Crist 6	11,377	1,200,162
	Crist 7	10,563	2,985,021
	Smith 1	10,642	937,637
	Smith 2	10,587	883,954
	Daniel 1	10,181	2,522,351
	Daniel 2	10,444	2,595,064
Jan. 2011 - Dec. 2011	Crist 4	11,712	184,555
	Crist 5	11,005	360,273
	Crist 6	11,450	857,072
	Crist 7	10,732	2,566,061
	Smith 1	10,750	576,442
	Smith 2	10,832	621,961
	Daniel 1	10,420	1,651,286
	Daniel 2	10,525	1,131,547
Jan. 2012 - Dec. 2012	Crist 4	11,692	99,356
	Crist 5	11,370	311,007
	Crist 6	10,709	920,562
	Crist 7	11,387	1,482,042
	Smith 1	10,800	503,897
	Smith 2	11,104	336,261
	Daniel 1	10,439	850,157
	Daniel 2	10,413	950,782

Interrogatory 8

		Heat Rate	
		Actual	Actual MWh
Jan. 2000 - Dec. 2000	Crist 6	10,527	1,611,616
	Crist 7	10,250	2,883,831
	Smith 1	10,079	1,207,534
	Smith 2	10,103	1,351,951
	Daniel 1	10,224	3,218,888
	Daniel 2	10,057	3,113,517
Jan. 2001 - Dec. 2001	Crist 6	10,996	1,498,344
	Crist 7	10,411	2,154,550
	Smith 1	10,129	1,124,207
	Smith 2	10,069	1,194,135
	Daniel 1	10,228	2,823,883
	Daniel 2	10,079	3,356,159
Jan. 2002 - Dec. 2002	Crist 4	11,351	386,953
	Crist 6	10,887	1,310,655
	Crist 7	10,388	2,498,708
	Smith 1	10,244	1,035,214
	Smith 2	10,409	733,260
	Daniel 1	10,095	3,182,817
	Daniel 2	10,036	2,578,411
Jan. 2003 - Dec. 2003	Crist 4	10,617	531,291
	Crist 5	10,621	508,220
	Crist 6	10,358	2,046,711
	Crist 7	10,287	3,337,257
	Smith 1	10,384	927,042
	Smith 2	10,191	927,793
	Daniel 1	9,839	2,761,190
	Daniel 2	9,781	3,282,470
Jan. 2004 - Dec. 2004	Crist 4	10,542	590,072
	Crist 5	10,629	587,904
	Crist 6	10,229	1,739,530
	Crist 7	10,365	2,558,568
	Smith 1	10,202	1,171,957
	Smith 2	10,353	1,327,414
	Daniel 1	10,066	3,169,684
	Daniel 2	9,833	3,937,610
Jan. 2005 - Dec. 2005	Crist 4	10,731	559,832
	Crist 5	10,659	538,897
	Crist 6	10,462	1,817,214
	Crist 7	10,722	2,107,672
	Smith 1	10,321	1,210,604
	Smith 2	10,336	1,158,713
	Daniel 1	10,189	3,381,992
	Daniel 2	10,154	3,685,619
Jan. 2006 - Dec. 2006	Crist 4	10,827	537,501
	Crist 5	10,741	536,930
	Crist 6	10,435	1,873,119
	Crist 7	10,487	3,344,607
	Smith 1	10,286	1,246,653
	Smith 2	10,346	1,388,830
	Daniel 1	10,109	4,095,727
	Daniel 2	10,093	3,316,959

		Heat Rate	
		Actual	Actual MWh
Jan. 2007 - Dec. 2007	Crist 4	11,004	547,538
	Crist 5	10,750	549,455
	Crist 6	10,701	2,045,960
	Crist 7	10,665	3,224,820
	Smith 1	10,255	974,625
	Smith 2	10,314	1,408,025
	Daniel 1	10,182	3,358,074
	Daniel 2	10,008	3,654,136
Jan. 2008 - Dec. 2008	Crist 4	10,762	337,807
	Crist 5	10,679	442,784
	Crist 6	10,912	1,390,244
	Crist 7	10,683	3,065,788
	Smith 1	10,285	1,098,164
	Smith 2	10,460	1,269,704
	Daniel 1	10,202	3,318,700
	Daniel 2	9,923	3,118,773
Jan. 2009 - Dec. 2009	Crist 4	10,816	222,242
	Crist 5	11,177	380,519
	Crist 6	11,205	937,988
	Crist 7	11,018	1,801,763
	Smith 1	10,689	516,735
	Smith 2	10,353	937,338
	Daniel 1	10,499	2,510,257
	Daniel 2	10,341	2,500,829
Jan. 2010 - Dec. 2010	Crist 4	11,679	247,278
	Crist 5	11,368	443,048
	Crist 6	11,377	1,200,162
	Crist 7	10,563	2,985,021
	Smith 1	10,642	937,637
	Smith 2	10,587	883,954
	Daniel 1	10,181	2,522,351
	Daniel 2	10,444	2,595,064
Jan. 2011 - Dec. 2011	Crist 4	11,712	184,555
	Crist 5	11,005	360,273
	Crist 6	11,450	857,072
	Crist 7	10,732	2,566,061
	Smith 1	10,750	576,442
	Smith 2	10,832	621,961
	Daniel 1	10,420	1,651,286
	Daniel 2	10,525	1,131,547
Jan. 2012 - Dec. 2012	Crist 4	11,692	99,356
	Crist 5	11,370	311,007
	Crist 6	10,709	920,562
	Crist 7	11,387	1,482,042
	Smith 1	10,800	503,897
	Smith 2	11,104	336,261
	Daniel 1	10,439	850,157
	Daniel 2	10,413	950,782

9. Please provide the projected GPIF Equivalent Availability Factor (EAF) target and the MW capacity of each GPIF unit for the years 2000 through 2012.

ANSWER:

See Attachment A, page 4 of 9

Interrogatory 9

		Equivalent Availability Factor	
		Target	MW Capacity
Jan. 2000 - Dec. 2000	Crist 6	84.30	302
	Crist 7	77.30	465
	Smith 1	90.60	162
	Smith 2	89.20	193
	Daniel 1	75.30	502
	Daniel 2	74.50	502
Jan. 2001 - Dec. 2001	Crist 6	78.10	302
	Crist 7	76.40	477
	Smith 1	88.70	162
	Smith 2	87.50	190
	Daniel 1	74.50	507
	Daniel 2	75.20	510
Jan. 2002 - Dec. 2002	Crist 4	90.90	78
	Crist 6	77.30	302
	Crist 7	79.70	477
	Smith 1	90.70	162
	Smith 2	86.60	189
	Daniel 1	88.00	507
	Daniel 2	70.70	510
Jan. 2003 - Dec. 2003	Crist 4	91.20	78
	Crist 5	89.80	80
	Crist 6	84.30	302
	Crist 7	79.50	477
	Smith 1	86.80	162
	Smith 2	67.80	189
	Daniel 1	70.10	507
	Daniel 2	83.00	514
Jan. 2004 - Dec. 2004	Crist 4	97.90	78
	Crist 5	96.80	80
	Crist 6	86.70	302
	Crist 7	70.10	477
	Smith 1	90.10	162
	Smith 2	82.80	189
	Daniel 1	69.60	507
	Daniel 2	81.10	514
Jan. 2005 - Dec. 2005	Crist 4	98.80	78
	Crist 5	96.90	80
	Crist 6	72.90	302
	Crist 7	70.90	477
	Smith 1	90.00	162
	Smith 2	72.20	189
	Daniel 1	79.00	514
	Daniel 2	88.20	514
Jan. 2006 - Dec. 2006	Crist 4	87.10	78
	Crist 5	92.40	80
	Crist 6	90.20	302
	Crist 7	80.80	477
	Smith 1	98.10	162
	Smith 2	84.10	189
	Daniel 1	93.60	514
	Daniel 2	81.50	514

		Equivalent Fa
		Target
Jan. 2007 - Dec. 2007	Crist 4	98.30
	Crist 5	97.10
	Crist 6	85.30
	Crist 7	83.50
	Smith 1	78.60
	Smith 2	89.40
	Daniel 1	82.50
	Daniel 2	93.90
Jan. 2008 - Dec. 2008	Crist 4	78.90
	Crist 5	89.00
	Crist 6	84.90
	Crist 7	82.10
	Smith 1	97.00
	Smith 2	83.90
	Daniel 1	93.80
	Daniel 2	77.60
Jan. 2009 - Dec. 2009	Crist 4	98.00
	Crist 5	96.40
	Crist 6	81.80
	Crist 7	68.70
	Smith 1	89.70
	Smith 2	95.90
	Daniel 1	81.20
	Daniel 2	89.70
Jan. 2010 - Dec. 2010	Crist 4	89.40
	Crist 5	96.30
	Crist 6	92.50
	Crist 7	87.60
	Smith 1	95.80
	Smith 2	89.90
	Daniel 1	77.70
	Daniel 2	87.80
Jan. 2011 - Dec. 2011	Crist 4	97.50
	Crist 5	81.20
	Crist 6	71.80
	Crist 7	82.50
	Smith 1	88.50
	Smith 2	95.40
	Daniel 1	94.00
	Daniel 2	77.00
Jan. 2012 - Dec. 2012	Crist 4	97.70
	Crist 5	97.90
	Crist 6	74.80
	Crist 7	72.60
	Smith 1	93.60
	Smith 2	87.70
	Daniel 1	84.10
	Daniel 2	93.40

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Interrogatory 9

		Equivalent Availability Factor	
		Target	MW Capacity
Jan. 2000 - Dec. 2000	Crist 6	84.30	302
	Crist 7	77.30	465
	Smith 1	90.60	162
	Smith 2	89.20	193
	Daniel 1	75.30	502
	Daniel 2	74.50	502
Jan. 2001 - Dec. 2001	Crist 6	78.10	302
	Crist 7	76.40	477
	Smith 1	88.70	162
	Smith 2	87.50	190
	Daniel 1	74.50	507
	Daniel 2	75.20	510
Jan. 2002 - Dec. 2002	Crist 4	90.90	78
	Crist 6	77.30	302
	Crist 7	79.70	477
	Smith 1	90.70	162
	Smith 2	86.60	189
	Daniel 1	88.00	507
	Daniel 2	70.70	510
Jan. 2003 - Dec. 2003	Crist 4	91.20	78
	Crist 5	89.80	80
	Crist 6	84.30	302
	Crist 7	79.50	477
	Smith 1	86.80	162
	Smith 2	67.80	189
	Daniel 1	70.10	507
	Daniel 2	83.00	514
Jan. 2004 - Dec. 2004	Crist 4	97.90	78
	Crist 5	96.80	80
	Crist 6	86.70	302
	Crist 7	70.10	477
	Smith 1	90.10	162
	Smith 2	82.80	189
	Daniel 1	69.60	507
	Daniel 2	81.10	514
Jan. 2005 - Dec. 2005	Crist 4	98.80	78
	Crist 5	96.90	80
	Crist 6	72.90	302
	Crist 7	70.90	477
	Smith 1	90.00	162
	Smith 2	72.20	189
	Daniel 1	79.00	514
	Daniel 2	88.20	514
Jan. 2006 - Dec. 2006	Crist 4	87.10	78
	Crist 5	92.40	80
	Crist 6	90.20	302
	Crist 7	80.80	477
	Smith 1	98.10	162
	Smith 2	84.10	189
	Daniel 1	93.60	514
	Daniel 2	81.50	514

		Equivalent Availability Factor	
		Target	MW Capacity
Jan. 2007 - Dec. 2007	Crist 4	98.30	78
	Crist 5	97.10	80
	Crist 6	85.30	302
	Crist 7	83.50	477
	Smith 1	78.60	162
	Smith 2	89.40	195
	Daniel 1	82.50	514
	Daniel 2	93.90	514
Jan. 2008 - Dec. 2008	Crist 4	78.90	78
	Crist 5	89.00	78
	Crist 6	84.90	302
	Crist 7	82.10	472
	Smith 1	97.00	162
	Smith 2	83.90	195
	Daniel 1	93.80	503
	Daniel 2	77.60	510
Jan. 2009 - Dec. 2009	Crist 4	98.00	78
	Crist 5	96.40	78
	Crist 6	81.80	301
	Crist 7	68.70	471
	Smith 1	89.70	162
	Smith 2	95.90	165
	Daniel 1	81.20	500
	Daniel 2	89.70	507
Jan. 2010 - Dec. 2010	Crist 4	89.40	75
	Crist 5	96.30	75
	Crist 6	92.50	291
	Crist 7	87.60	465
	Smith 1	95.80	162
	Smith 2	89.90	195
	Daniel 1	77.70	510
	Daniel 2	87.80	510
Jan. 2011 - Dec. 2011	Crist 4	97.50	75
	Crist 5	81.20	75
	Crist 6	71.80	291
	Crist 7	82.50	465
	Smith 1	88.50	162
	Smith 2	95.40	195
	Daniel 1	94.00	510
	Daniel 2	77.00	510
Jan. 2012 - Dec. 2012	Crist 4	97.70	75
	Crist 5	97.90	75
	Crist 6	74.80	297
	Crist 7	72.60	467
	Smith 1	93.60	162
	Smith 2	87.70	195
	Daniel 1	84.10	510
	Daniel 2	93.40	510

10. Please provide the actual GPIF Equivalent Availability Factor (EAF) performance and the MW capacity for each GPIF unit for the years 2000 through 2012.

ANSWER:

See Attachment A, page 5 of 9

Interrogatory 10

		Equivalent Availability Factor	
		GPIF EAF	MW Capacity
Jan. 2000 - Dec. 2000	Crist 6	73.50	302
	Crist 7	79.20	475
	Smith 1	92.60	162
	Smith 2	91.50	190
	Daniel 1	80.00	494
	Daniel 2	81.30	502
Jan. 2001 - Dec. 2001	Crist 6	76.60	302
	Crist 7	65.30	477
	Smith 1	90.80	162
	Smith 2	88.60	189
	Daniel 1	82.70	500
	Daniel 2	80.70	510
Jan. 2002 - Dec. 2002	Crist 4	93.10	78
	Crist 6	78.30	302
	Crist 7	85.80	477
	Smith 1	92.00	162
	Smith 2	58.20	189
	Daniel 1	92.40	501
	Daniel 2	73.90	513
Jan. 2003 - Dec. 2003	Crist 4	92.30	78
	Crist 5	91.40	80
	Crist 6	89.40	302
	Crist 7	89.50	477
	Smith 1	83.20	162
	Smith 2	69.30	189
	Daniel 1	73.40	507
	Daniel 2	89.20	514
Jan. 2004 - Dec. 2004	Crist 4	98.50	78
	Crist 5	98.70	80
	Crist 6	75.50	302
	Crist 7	70.10	477
	Smith 1	91.60	162
	Smith 2	90.40	189
	Daniel 1	70.80	514
	Daniel 2	85.30	500
Jan. 2005 - Dec. 2005	Crist 4	98.20	78
	Crist 5	92.50	80
	Crist 6	76.00	302
	Crist 7	54.20	477
	Smith 1	90.70	162
	Smith 2	76.10	189
	Daniel 1	77.10	514
	Daniel 2	87.10	500
Jan. 2006 - Dec. 2006	Crist 4	87.00	78
	Crist 5	93.20	80
	Crist 6	93.00	302
	Crist 7	84.70	477
	Smith 1	94.10	162
	Smith 2	87.90	195
	Daniel 1	95.20	514
	Daniel 2	80.80	500

		Equivalent Fac
		GPIF EAF
Jan. 2007 - Dec. 2007	Crist 4	98.90
	Crist 5	98.10
	Crist 6	87.80
	Crist 7	88.70
	Smith 1	76.20
	Smith 2	97.70
	Daniel 1	84.80
	Daniel 2	93.70
Jan. 2008 - Dec. 2008	Crist 4	76.60
	Crist 5	89.20
	Crist 6	81.80
	Crist 7	85.10
	Smith 1	93.70
	Smith 2	86.10
	Daniel 1	84.30
	Daniel 2	75.00
Jan. 2009 - Dec. 2009	Crist 4	99.60
	Crist 5	96.10
	Crist 6	87.00
	Crist 7	69.00
	Smith 1	86.90
	Smith 2	96.30
	Daniel 1	81.80
	Daniel 2	81.30
Jan. 2010 - Dec. 2010	Crist 4	90.50
	Crist 5	98.40
	Crist 6	93.10
	Crist 7	94.20
	Smith 1	94.80
	Smith 2	87.30
	Daniel 1	78.20
	Daniel 2	92.50
Jan. 2011 - Dec. 2011	Crist 4	94.90
	Crist 5	83.80
	Crist 6	67.20
	Crist 7	87.00
	Smith 1	89.40
	Smith 2	90.10
	Daniel 1	82.60
	Daniel 2	74.10
Jan. 2012 - Dec. 2012	Crist 4	99.40
	Crist 5	98.80
	Crist 6	73.40
	Crist 7	75.50
	Smith 1	92.60
	Smith 2	86.30
	Daniel 1	75.70
	Daniel 2	89.50

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510

Interrogatory 10

		Equivalent Availability Factor	
		GPIF EAF	MW Capacity
Jan. 2000 - Dec. 2000	Crist 6	73.50	302
	Crist 7	79.20	475
	Smith 1	92.60	162
	Smith 2	91.50	190
	Daniel 1	80.00	494
	Daniel 2	81.30	502
Jan. 2001 - Dec. 2001	Crist 6	76.60	302
	Crist 7	65.30	477
	Smith 1	90.80	162
	Smith 2	88.60	189
	Daniel 1	82.70	500
	Daniel 2	80.70	510
Jan. 2002 - Dec. 2002	Crist 4	93.10	78
	Crist 6	78.30	302
	Crist 7	85.80	477
	Smith 1	92.00	162
	Smith 2	58.20	189
	Daniel 1	92.40	501
	Daniel 2	73.90	513
Jan. 2003 - Dec. 2003	Crist 4	92.30	78
	Crist 5	91.40	80
	Crist 6	89.40	302
	Crist 7	89.50	477
	Smith 1	83.20	162
	Smith 2	69.30	189
	Daniel 1	73.40	507
	Daniel 2	89.20	514
Jan. 2004 - Dec. 2004	Crist 4	98.50	78
	Crist 5	98.70	80
	Crist 6	75.50	302
	Crist 7	70.10	477
	Smith 1	91.60	162
	Smith 2	90.40	189
	Daniel 1	70.80	514
	Daniel 2	85.30	500
Jan. 2005 - Dec. 2005	Crist 4	98.20	78
	Crist 5	92.50	80
	Crist 6	76.00	302
	Crist 7	54.20	477
	Smith 1	90.70	162
	Smith 2	76.10	189
	Daniel 1	77.10	514
	Daniel 2	87.10	500
Jan. 2006 - Dec. 2006	Crist 4	87.00	78
	Crist 5	93.20	80
	Crist 6	93.00	302
	Crist 7	84.70	477
	Smith 1	94.10	162
	Smith 2	87.90	195
	Daniel 1	95.20	514
	Daniel 2	80.80	500

		Equivalent Availability Factor	
		GPIF EAF	MW Capacity
Jan. 2007 - Dec. 2007	Crist 4	98.90	78
	Crist 5	98.10	78
	Crist 6	87.80	302
	Crist 7	88.70	472
	Smith 1	76.20	162
	Smith 2	97.70	195
	Daniel 1	84.80	503
	Daniel 2	93.70	510
Jan. 2008 - Dec. 2008	Crist 4	76.60	78
	Crist 5	89.20	78
	Crist 6	81.80	302
	Crist 7	85.10	472
	Smith 1	93.70	162
	Smith 2	86.10	195
	Daniel 1	84.30	500
	Daniel 2	75.00	507
Jan. 2009 - Dec. 2009	Crist 4	99.60	78
	Crist 5	96.10	78
	Crist 6	87.00	302
	Crist 7	69.00	472
	Smith 1	86.90	162
	Smith 2	96.30	195
	Daniel 1	81.80	510
	Daniel 2	81.30	510
Jan. 2010 - Dec. 2010	Crist 4	90.50	75
	Crist 5	98.40	75
	Crist 6	93.10	291
	Crist 7	94.20	465
	Smith 1	94.80	162
	Smith 2	87.30	195
	Daniel 1	78.20	510
	Daniel 2	92.50	510
Jan. 2011 - Dec. 2011	Crist 4	94.90	75
	Crist 5	83.80	75
	Crist 6	67.20	291
	Crist 7	87.00	465
	Smith 1	89.40	162
	Smith 2	90.10	195
	Daniel 1	82.60	510
	Daniel 2	74.10	510
Jan. 2012 - Dec. 2012	Crist 4	99.40	75
	Crist 5	98.80	75
	Crist 6	73.40	297
	Crist 7	75.50	467
	Smith 1	92.60	162
	Smith 2	86.30	195
	Daniel 1	75.70	510
	Daniel 2	89.50	510

Interrogatory 11

	Base Load units	GADS HR	Annual Annual Change	Total MWh	Fuel Price $$/mmBTU	Estimated Fuel Cost Savings due to change	Total for the Period
11 (a)	1982	10,628		7,328,731	$225.63		
	1983	10,932		7,660,437	$235.98	$5,497,561	
	1984	10,489		8,242,411	$240.59	-$8,795,821	
	1985	10,485		8,533,873	$250.71	-$78,370	
	1986	10,478		8,410,671	$236.17	-$140,743	
	1987	10,383		10,974,387	$183.68	-$1,918,482	
	1988	10,325		10,653,676	$164.79	-$1,005,165	
	1989	10,555	-9.20	8,505,555	$185.89	$3,620,981	-$2,820,039
	1990	10,564		7,522,635	$202.50	$137,131	
11 (b)	1991	10,431		9,175,566	$194.80	-$2,372,352	
	1992	10,342		9,820,670	$203.59	-$1,777,568	
	1993	10,394		8,578,445	$199.46	$898,011	
	1994	10,441		8,343,685	$181.06	$700,715	
	1995	10,625		8,422,250	$183.97	$2,861,263	
	1996	10,409		8,692,516	$176.38	-$3,324,986	
	1997	10,417		9,312,485	$177.65	$147,773	
	1998	10,405		10,636,160	$155.47	-$207,138	
	1999	10,266	-33	11,558,916	$154.56	-$2,490,481	-$5,427,633
	2000	10,251		11,474,382	$151.83	-$252,560	
11 (c)	2001	10,325		10,062,658	$159.95	$1,196,350	
	2002	10,363		9,470,943	$166.28	$591,683	
	2003	10,144		11,646,923	$163.90	-$4,171,884	
	2004	10,239		11,908,113	$180.37	$2,029,302	
	2005	10,386		11,269,419	$222.49	$3,693,241	
	2006	10,316		12,851,045	$264.72	-$2,385,485	
	2007	10,393		12,641,593	$279.90	$2,709,612	
	2008	10,413		11,079,576	$351.20	$774,191	
	2009	10,704	50	7,253,965	$412.17	$8,704,934	$12,889,385
	2010	10,654		9,302,258	$504.31	-$2,315,627	
11 (d)	2011	10,893		6,562,918	$474.37	$7,443,131	
	2012	11,084	215	4,134,336	$447.01	$3,522,562	$8,650,066

Note: 1980 and 1981 data is not available

	GPIF Units	MWh Weighted Target Heat Rate	Annual Annual Change
11 (g)	1981	10,731	
	1982		
	1983		
	1984		
	1985		
	1986		
	1987		
	1988		
	1989	10,549	-23
11 (h)	1990	10,619	
	1991		
	1992		
	1993		
	1994		
	1995		
	1996		
	1997		
	1998		
	1999	10,346	-30
11 (i)	2000	10,252	
	2001		
	2002		
	2003		
	2004		
	2005		
	2006		
	2007		
	2008		
	2009	10,224	-3
11 (j)	2010	10,494	
	2011		
	2012	10,853	179

Note: Only partial data is available for 1980

11. Please describe the improvement or decline in your company's heat rate performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

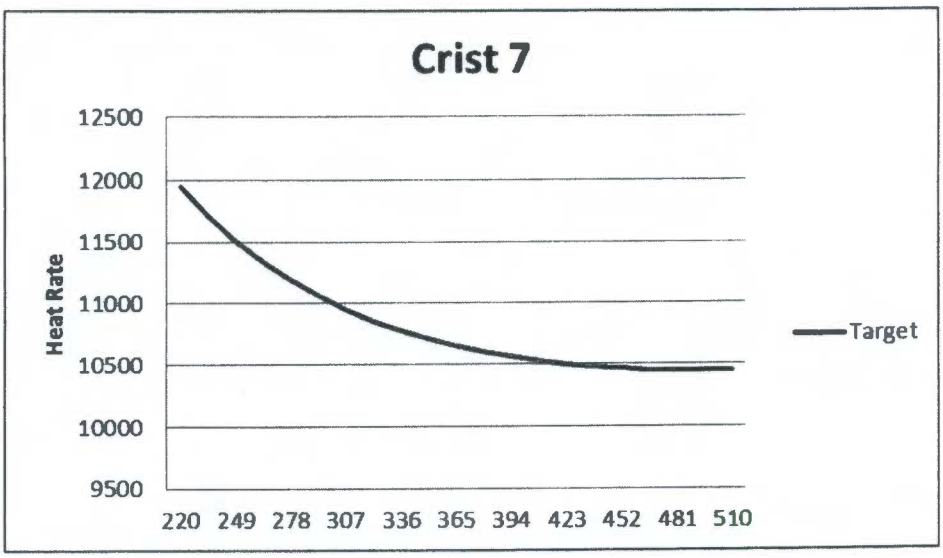
(a) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89;
(b) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1990-99;
(c) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2000-09;
(d) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2010-12;
(e) The amount of capital and O&M required and deployed for the heat rate improvement in each period;
(f) The amount of net GPIF incentive payments for the heat rate performance in each period (annual and cumulative);
(g) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1980-89;
(h) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1990-99;
(i) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2000-09;
(j) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2010-12;
(k) The alternative analysis (if any).

ANSWER:

The heat rate from the early 1980's to 2008 trended downward in part due to improved maintenance strategies and increased load on the system. Gulf's base load units are fueled with pulverized coal and are designed to run at full load. As the unit's load increases, the unit's heat rate decreases and the heat rate curve will stabilize at loads in the 80% to 100% range. The chart below shows the relationship between heat rate and load using Crist Unit 7 as an example. Therefore, as the system load increases, the

units stay loaded longer per day and the overall heat rate decreases. For the period 1984 to 2008, the average heat rate was consistently around 10,393 Btu/kWh. The standard deviation calculates to be 108 Btu/kWh which is about 1%. The heat rates for the period 2009 to present illustrate the effect of the units operating at lower loads. Operating a pulverized coal unit at lower loads results in a nonlinear increase in heat rate (as illustrated in the chart below). Since the capacity factors of the units have decreased from 2009 until present the average heat rate has increased.

Commission policies have not had an impact on Gulf's heat rate and/or operation of our units. Our planning, operation and maintenance has been implemented to optimize our generating units' reliability and performance. A more detailed explanation of this strategy is outlined in the response to 11(e).



(a) See Attachment A, page 6 of 9

(b) See Attachment A, page 6 of 9

(c) See Attachment A, page 6 of 9

(d) See Attachment A, page 6 of 9

(e) The capital and Operations & Maintenance (O&M) dollars included in our annual budget are developed to optimize performance and reliability. Specific dollars are

not attributable to a change in performance or reliability. However, the entire budgeting process is focused on the continued safe, reliable and efficient operation of the units as a whole. Gulf takes advantage of our production staff's extensive knowledge and experience as well as monitoring programs (such as condition based maintenance) to maximize effectiveness of our planned outage programs and our online maintenance program. Since all mechanical and electrical equipment performance degrades over time, it is understood that capital and O&M money will be necessary to maintain and replace equipment. Wear is a symptom of run time. Staggering major equipment maintenance is necessary in order to avoid major swings in capital and O&M expenditures. This planning process is applied across Gulf's generation fleet to maximize unit availability, reliability and efficiency. For example, as performance and reliability degrade on one unit over time another unit undergoes major maintenance to improve its performance and reliability. Therefore a change in the performance and reliability of the fleet may not result in a measured change in heat rate or availability. Gulf's consistent overall high level of performance and reliability exemplifies the success of a well planned and executed budgeting and maintenance strategy.

(f) See Attachment A, page 7 of 9

(g) See Attachment A, page 6 of 9

(h) See Attachment A, page 6 of 9

(i) See Attachment A, page 6 of 9

(j) See Attachment A, page 6 of 9

(k) N/A

Interrogatory 11

	Base Load Units	GADS HR	Annual Annual Change	Total MWh	Fuel Price $$/mmBTU	Estimated Fuel Cost Savings due to change	Total for the Period
11 (a)	1982	10,628		7,328,731	$225.63		
	1983	10,932		7,660,437	$235.98	$5,497,561	
	1984	10,489		8,242,411	$240.59	-$8,795,821	
	1985	10,485		8,533,873	$250.71	-$78,370	
	1986	10,478		8,410,671	$236.17	-$140,743	
	1987	10,383		10,974,387	$183.68	-$1,918,482	
	1988	10,325		10,653,676	$164.79	-$1,005,165	
	1989	10,555	-9.20	8,505,555	$185.89	$3,620,981	-$2,820,039
	1990	10,564		7,522,635	$202.50	$137,131	
11 (b)	1991	10,431		9,175,566	$194.80	-$2,372,352	
	1992	10,342		9,820,670	$203.59	-$1,777,568	
	1993	10,394		8,578,445	$199.46	$898,011	
	1994	10,441		8,343,685	$181.06	$700,715	
	1995	10,625		8,422,250	$183.97	$2,861,263	
	1996	10,409		8,692,516	$176.38	-$3,324,986	
	1997	10,417		9,312,485	$177.65	$147,773	
	1998	10,405		10,636,160	$155.47	-$207,138	
	1999	10,266	-33	11,558,916	$154.56	-$2,490,481	-$5,427,633
	2000	10,251		11,474,382	$151.83	-$252,560	
11 (c)	2001	10,325		10,062,658	$159.95	$1,196,350	
	2002	10,363		9,470,943	$166.28	$591,683	
	2003	10,144		11,646,923	$163.90	-$4,171,884	
	2004	10,239		11,908,113	$180.37	$2,029,302	
	2005	10,386		11,269,419	$222.49	$3,693,241	
	2006	10,316		12,851,045	$264.72	-$2,385,485	
	2007	10,393		12,641,593	$279.90	$2,709,612	
	2008	10,413		11,079,576	$351.20	$774,191	
	2009	*10,704*	*50*	*7,253,965*	*$412.17*	*$8,704,934*	*$12,669,365*
	2010	10,654		9,302,258	$504.31	-$2,315,627	
11 (d)	2011	10,893		6,562,918	$474.37	$7,443,131	
	2012	11,084	215	4,134,336	$447.01	$3,522,562	$8,650,066

Note: 1980 and 1981 data is not available

	GPIF Units	MWh Weighted Target Heat Rate	Annual Annual Change
11 (g)	1981	10,731	
	1982		
	1983		
	1984		
	1985		
	1986		
	1987		
	1988		
	1989	10,549	-23
11 (h)	1990	10,619	
	1991		
	1992		
	1993		
	1994		
	1995		
	1996		
	1997		
	1998		
	1999	10,346	-30
11 (i)	2000	10,252	
	2001		
	2002		
	2003		
	2004		
	2005		
	2006		
	2007		
	2008		
	2009	10,224	-3
11 (j)	2010	10,494	
	2011		
	2012	10,853	179

Note: Only partial data is available for 1980

130001 Hearing Exhibits - 00452

Interrogatory 11(f)

Data Period	Unit	Weighting % EAF	Weighting % Heat Rate	GPIF Reward/Penalty	Heat Rate Reward/Penalty	Heat Rate Reward/Penalty Cumulative
Oct. 1980 - Mar. 1981	Gulf	11.11	88.89	$124,000	$110,224	$110,224
Apr. 1981 - Sept. 1981	Gulf	12.05	87.95	($36,410)	($32,023)	$78,201
Oct. 1981 - Mar. 1982	Gulf	14.00	86.00	($62,994)	($54,175)	$24,026
Apr. 1982 - Sep. 1982	Gulf	16.40	83.60	$195,101	$163,104	$187,131
Oct. 1982 - Mar. 1983	Data Not Available			$161,311	$137,114	$324,245
Apr. 1983 - Sep. 1983	Data Not Available			$373,500	$317,475	$641,720
Oct. 1983 - Mar. 1984	Gulf	27.80	72.20	$121,499	$87,722	$729,442
Apr. 1984 - Sep. 1984	Gulf	10.60	89.40	$308,902	$276,158	$1,005,601
Oct. 1984 - Mar. 1985	Gulf	17.00	83.00	$396,412	$329,022	$1,334,623
Apr. 1985 - Sep. 1985	Gulf	8.00	92.00	$157,858	$145,229	$1,479,852
Oct. 1985 - Mar. 1986	Gulf	5.20	94.80	$12,063	$11,436	$1,491,288
Apr. 1986 - Sep. 1986	Gulf	8.30	91.70	$100,497	$92,156	$1,583,443
Oct. 1986 - Mar. 1987	Gulf	3.30	96.70	($70,065)	($67,753)	$1,515,691
Apr. 1987 - Sep. 1987	Gulf	7.10	91.90	($98,446)	($90,472)	$1,425,219
Oct. 1987 - Mar. 1988	Gulf	14.90	85.10	($153,932)	($130,996)	$1,294,223
Apr. 1988 - Sep. 1988	Gulf	16.00	84.00	$76,007	$63,846	$1,358,068
Oct. 1988 - Mar. 1989	Gulf	21.50	78.50	$102,569	$80,517	$1,438,585
Apr. 1989 - Sep. 1989	Gulf	5.10	94.90	($101,127)	($95,970)	$1,342,616
Oct 1989 - Mar. 1990	Gulf	18.70	81.20	$130,155	$105,686	$1,448,301
Apr. 1990 - Sep. 1990	Gulf	23.60	76.50	$72,091	$55,150	$1,503,451
Oct. 1990 - Mar. 1991	Gulf	23.20	77.00	($93,473)	($71,974)	$1,431,477
Apr. 1991 - Sep. 1991	Gulf	13.10	86.80	($213,475)	($185,296)	$1,246,181
Oct. 1991 - Mar. 1992	Gulf	3.40	96.60	$87,028	$84,069	$1,330,250
Apr. 1992 - Sep. 1992	Gulf	23.10	77.00	$322,504	$248,328	$1,578,578
Oct. 1992 - Mar. 1993	Gulf	4.60	95.50	$372,865	$356,086	$1,934,664
Apr. 1993 - Sep. 1993	Gulf	17.50	82.50	$128,552	$106,055	$2,040,719
Oct. 1993 - Mar. 1994	Gulf	15.00	85.00	($84,941)	($72,200)	$1,968,519
Apr. 1994 - Sep. 1994	Gulf	15.80	84.30	$22,931	$19,331	$1,987,850
Oct. 1994 - Mar. 1995	Gulf	10.90	41.00	$0	$0	$1,987,850
Apr. 1995 - Sept. 1995	Gulf	9.70	90.30	($483,077)	($436,219)	$1,551,632
Oct. 1995 - Mar. 1996	Gulf	3.30	54.20	($44,234)	($23,975)	$1,527,657
Apr. 1996 - Sept. 1996	Gulf	6.60	93.30	$82,198	$76,691	$1,604,347
Oct. 1996 - Mar. 1997	Gulf	3.20	96.60	$11,349	$10,963	$1,615,311
Apr. 1997 - Sept. 1997	Gulf	10.40	89.60	($300,745)	($269,468)	$1,345,843
Oct. 1997 - Mar. 1998	Gulf	3.90	96.10	$62,632	$60,189	$1,406,032
Apr. 1998 - Sept. 1998	Gulf	31.30	68.90	($75,355)	($51,920)	$1,354,113
Oct. 1998 - Dec. 1998	Gulf	22.90	77.10	$38,676	$29,819	$1,383,932
Jan. 1999 - Dec. 1999	Gulf	23.00	76.90	$183,842	$141,374	$1,525,307
Jan. 2000 - Dec. 2000	Gulf	26.70	73.20	$379,732	$277,964	$1,803,270
Jan. 2001 - Dec. 2001	Gulf	26.10	73.90	($369,498)	($273,059)	$1,530,211
Jan. 2002 - Dec. 2002	Gulf	33.20	66.80	$431,920	$288,523	$1,818,734
Jan. 2003 - Dec. 2003	Gulf	27.50	72.60	$625,280	$453,953	$2,272,687
Jan. 2004 - Dec. 2004	Gulf	24.20	75.70	$441,988	$334,585	$2,607,272
Jan. 2005 - Dec. 2005	Gulf	20.40	79.50	($842,874)	($670,085)	$1,937,187
Jan. 2006 - Dec. 2006	Gulf	18.12	81.88	($205,097)	($167,931)	$1,769,256
Jan. 2007 - Dec. 2007	Gulf	26.51	73.49	($690,892)	($507,727)	$1,261,529
Jan. 2008 - Dec. 2008	Gulf	18.51	81.45	$113,177	$92,186	$1,353,715
Jan. 2009 - Dec. 2009	Gulf	15.73	84.26	$257,966	$217,351	$1,571,066
Jan. 2010 - Dec. 2010	Gulf	9.94	90.07	$819,302	$737,945	$2,309,012
Jan. 2011 - Dec. 2011	Gulf	4.19	95.81	$1,040,660	$997,079	$3,306,091
Jan. 2012 - Dec. 2012	Gulf	8.00	92.00	$1,662,342	$1,529,355	$4,835,446

Interrogatory 11(f)

Data Period	Unit	Weighting % EAF	Weighting % Heat Rate	GPIF Reward/Penalty	Heat Rate Reward/Penalty	Heat Rate Reward/Penalty Cumulative
Oct. 1980 - Mar. 1981	Gulf	11.11	88.89	$124,000	$110,224	$110,224
Apr. 1981 - Sept. 1981	Gulf	12.05	87.95	($36,410)	($32,023)	$78,201
Oct. 1981 - Mar. 1982	Gulf	14.00	86.00	($62,994)	($54,175)	$24,026
Apr. 1982 - Sep. 1982	Gulf	16.40	83.60	$195,101	$163,104	$187,131
Oct. 1982 - Mar. 1983	Data Not Available			$161,311	$137,114	$324,245
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Apr. 1984 - Sep. 1984	Gulf	10.60	89.40	$308,902	$276,158	$1,005,601
Oct. 1984 - Mar. 1985	Gulf	17.00	83.00	$396,412	$329,022	$1,334,623
Apr. 1985 - Sep. 1985	Gulf	8.00	92.00	$157,858	$145,229	$1,479,852
Oct. 1985 - Mar. 1986	Gulf	5.20	94.80	$12,063	$11,436	$1,491,288
Apr. 1986 - Sep. 1986	Gulf	8.30	91.70	$100,497	$92,156	$1,583,443
Oct. 1986 - Mar. 1987	Gulf	3.30	96.70	($70,065)	($67,753)	$1,515,691
Apr. 1987 - Sep. 1987	Gulf	7.10	91.90	($98,446)	($90,472)	$1,425,219
Oct. 1987 - Mar. 1988	Gulf	14.90	85.10	($153,932)	($130,996)	$1,294,223
Apr. 1988 - Sep. 1988	Gulf	16.00	84.00	$76,007	$63,846	$1,358,068
Oct. 1988 - Mar. 1989	Gulf	21.50	78.50	$102,569	$80,517	$1,438,585
Apr. 1989 - Sep. 1989	Gulf	5.10	94.90	($101,127)	($95,970)	$1,342,616
Oct 1989 - Mar. 1990	Gulf	18.70	81.20	$130,155	$105,686	$1,448,301
Apr. 1990 - Sep. 1990	Gulf	23.60	76.50	$72,091	$55,150	$1,503,451
Oct. 1990 - Mar. 1991	Gulf	23.20	77.00	($93,473)	($71,974)	$1,431,477
Apr. 1991 - Sep. 1991	Gulf	13.10	86.80	($213,475)	($185,296)	$1,246,181
Oct. 1991 - Mar. 1992	Gulf	3.40	96.60	$87,028	$84,069	$1,330,250
Apr. 1992 - Sep. 1992	Gulf	23.10	77.00	$322,504	$248,328	$1,578,578
Oct. 1992 - Mar. 1993	Gulf	4.60	95.50	$372,865	$356,086	$1,934,664
Apr. 1993 - Sep. 1993	Gulf	17.50	82.50	$128,552	$106,055	$2,040,719
Oct. 1993 - Mar. 1994	Gulf	15.00	85.00	($84,941)	($72,200)	$1,968,519
Apr. 1994 - Sep. 1994	Gulf	15.80	84.30	$22,931	$19,331	$1,987,850
Oct. 1994 - Mar. 1995	Gulf	10.90	41.00	$0	$0	$1,987,850
Apr. 1995 - Sept. 1995	Gulf	9.70	90.30	($483,077)	($436,219)	$1,551,632
Oct. 1995 - Mar. 1996	Gulf	3.30	54.20	($44,234)	($23,975)	$1,527,657
Apr. 1996 - Sept. 1996	Gulf	6.60	93.30	$82,198	$76,691	$1,604,347
Oct. 1996 - Mar. 1997	Gulf	3.20	96.60	$11,349	$10,963	$1,615,311
Apr. 1997 - Sept. 1997	Gulf	10.40	89.60	($300,745)	($269,468)	$1,345,843
Oct. 1997 - Mar. 1998	Gulf	3.90	96.10	$62,632	$60,189	$1,406,032
Apr. 1998 - Sept. 1998	Gulf	31.30	68.90	($75,355)	($51,920)	$1,354,113
Oct. 1998 - Dec. 1998	Gulf	22.90	77.10	$38,676	$29,819	$1,383,932
Jan. 1999 - Dec. 1999	Gulf	23.00	76.90	$183,842	$141,374	$1,525,307
Jan. 2000 - Dec. 2000	Gulf	26.70	73.20	$379,732	$277,964	$1,803,270
Jan. 2001 - Dec. 2001	Gulf	26.10	73.90	($369,498)	($273,059)	$1,530,211
Jan. 2002 - Dec. 2002	Gulf	33.20	66.80	$431,920	$288,523	$1,818,734
Jan. 2003 - Dec. 2003	Gulf	27.50	72.60	$625,280	$453,953	$2,272,687
Jan. 2004 - Dec. 2004	Gulf	24.20	75.70	$441,988	$334,585	$2,607,272
Jan. 2005 - Dec. 2005	Gulf	20.40	79.50	($842,874)	($670,085)	$1,937,187
Jan. 2006 - Dec. 2006	Gulf	18.12	81.88	($205,097)	($167,931)	$1,769,256
Jan. 2007 - Dec. 2007	Gulf	26.51	73.49	($690,892)	($507,727)	$1,261,529
Jan. 2008 - Dec. 2008	Gulf	18.51	81.45	$113,177	$92,186	$1,353,715
Jan. 2009 - Dec. 2009	Gulf	15.73	84.26	$257,966	$217,351	$1,571,066
Jan. 2010 - Dec. 2010	Gulf	9.94	90.07	$819,302	$737,945	$2,309,012
Jan. 2011 - Dec. 2011	Gulf	4.19	95.81	$1,040,660	$997,079	$3,306,091
Jan. 2012 - Dec. 2012	Gulf	8.00	92.00	$1,662,342	$1,529,355	$4,835,446

12. Please describe the improvement or decline in your company's availability performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

(a) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89;
(b) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1990-99;
(c) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2000-09;
(d) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2010-12;
(e) The amount of capital and O&M required and deployed for the improvement in each period;
(f) The amount of net GPIF incentive payments for the availability factor performance in each period (annual and cumulative);
(g) The annual average rate of change in the composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1980-89;
(h) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1990-99;
(i) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2000-09;
(j) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2010-12;
(k) The alternative analysis (if any).

ANSWER:

The availability performance for Gulf's base load units from the early 1980's until 2009 has averaged 82.1 with a standard deviation of 3.3. In comparing the end points of the period from beginning to present, availability has trended upward but within the period generally cycles above and below the mean. The past three years have shown the highest levels of availability reflecting the amount of reserve shut down hours that the coal units are experiencing as a result of lower natural gas prices. While on reserve

shut down, a generating unit is deemed 100% available and tends to increase the average availability percentage. Years with lower average availability percentages tend to coincide with years when units that are having major planned outage as Planned Outage hours have zero availability. It is Gulf's focus, as shown and detailed in our budgeting process, to maintain the highest availability possible when the units are not on Planned Outage.

Commission policies have not had any impact on Gulf's reliability and/or operation of our units. Our planning, operation and maintenance has been implemented to optimize our reliability and performance. A more detailed explanation of this strategy is outlined in the response to 11(e).

12 (a)-(d)
The annual average rate of improvement in availability factor for the periods 1980-89, 1990-99, 2000-09, and 2010-12 are presented on Attachment A page 8 of 9.

Gulf is not able to quantify the estimated fuel savings achieved due to improvement in availability factor performance as requested. The number of parameters that would be involved in determining amounts with any reasonable level of accuracy is not possible. On an hourly basis, items that would need to be considered include, but are not limited to, the amount of generation for each of Gulf's generating units, the fuel cost or purchased power cost that would have been incurred if one or more of Gulf's units were not available, or the cost of avoided fuel/purchased power energy as a result of one or more of Gulf's units being available. These are reasons why a modeling program is used to determine values specific to each unit's availability for the GPIF targets.

(e) See Gulf's Response to item 11(e)

(f) See Attachment A, page 9 of 9

(g) See Attachment A, page 8 of 9

(h) See Attachment A, page 8 of 9

(i) See Attachment A, page 8 of 9

(j) See Attachment A, page 8 of 9

(k) N/A

Interrogatory 12

Base Load

	Units Period	EAF	Annual Annual Change
	1982	79.63	
	1983	79.73	
	1984	82.55	
	1985	81.59	
	1986	78.24	
	1987	84.21	
	1988	83.37	
12 (a)	1989	85.14	0.79
	1990	82.89	
	1991	75.18	
	1992	79.96	
	1993	81.65	
	1994	83.76	
	1995	83.87	
	1996	80.70	
	1997	81.40	
	1998	75.54	
12 (b)	1999	81.85	-0.12
	2000	82.69	
	2001	84.59	
	2002	79.57	
	2003	81.82	
	2004	83.67	
	2005	77.80	
	2006	87.98	
	2007	89.75	
	2008	84.72	
12 (c)	2009	85.47	0.31
	2010	90.30	
	2011	77.24	
12 (d)	2012	84.54	-2.88

Note: 1980 and 1981 data is not available

	GPIF	MW Weighted	Annual Annual Change
	1981	74.78	
	1982		
	1983		
	1984		
	1985		
	1986		
	1987		
	1988		
12 (g)	1989	79.84	0.63
	1990	79.58	
	1991		
	1992		
	1993		
	1994		
	1995		
	1996		
	1997		
	1998		
12 (h)	1999	81.25	0.19
	2000	79.25	
	2001		
	2002		
	2003		
	2004		
	2005		
	2006		
	2007		
	2008		
12 (i)	2009	83.52	0.47
	2010	87.18	
	2011		
12 (j)	2012	84.53	-1.32

Note: Only partial data is available for 1980

Interrogatory 12(f)

Data Period	Unit	Weighting % EAF	Weighting % Heat Rate	GPIF Reward/Penalty	Equivalent Availability Reward/Penalty	Equivalent Availability Reward/Penalty Cumulative
Oct. 1980 - Mar. 1981	Gulf	11.11	88.89	$124,000	$13,776	$13,776
Apr. 1981 - Sept. 1981	Gulf	12.05	87.95	($36,410)	($4,387)	$9,389
Oct. 1981 - Mar. 1982	Gulf	14.00	86.00	($62,994)	($8,819)	$570
Apr. 1982 - Sep. 1982	Gulf	16.40	83.60	$195,101	$31,997	$32,566
Oct. 1982 - Mar. 1983	Data Not Available			$161,311	$0	$32,566
Apr. 1983 - Sep. 1983	Data Not Available			$373,500	$0	$32,566
Oct. 1983 - Mar. 1984	Gulf	27.80	72.20	$121,499	$33,777	$66,343
Apr. 1984 - Sep. 1984	Gulf	10.60	89.40	$308,902	$32,744	$99,087
Oct. 1984 - Mar. 1985	Gulf	17.00	83.00	$396,412	$67,390	$166,477
Apr. 1985 - Sep. 1985	Gulf	8.00	92.00	$157,858	$12,629	$179,105
Oct. 1985 - Mar. 1986	Gulf	5.20	94.80	$12,063	$627	$179,733
Apr. 1986 - Sep. 1986	Gulf	8.30	91.70	$100,497	$8,341	$188,074
Oct. 1986 - Mar. 1987	Gulf	3.30	96.70	($70,065)	($2,312)	$185,762
Apr. 1987 - Sep. 1987	Gulf	7.10	91.90	($98,446)	($6,990)	$178,772
Oct. 1987 - Mar. 1988	Gulf	14.90	85.10	($153,932)	($22,936)	$155,836
Apr. 1988 - Sep. 1988	Gulf	16.00	84.00	$76,007	$12,161	$167,997
Oct. 1988 - Mar. 1989	Gulf	21.50	78.50	$102,569	$22,052	$190,050
Apr. 1989 - Sep. 1989	Gulf	5.10	94.90	($101,127)	($5,157)	$184,892
Oct 1989 - Mar. 1990	Gulf	18.70	81.20	$130,155	$24,339	$209,231
Apr. 1990 - Sep. 1990	Gulf	23.60	76.50	$72,091	$17,013	$226,245
Oct. 1990 - Mar. 1991	Gulf	23.20	77.00	($93,473)	($21,686)	$204,559
Apr. 1991 - Sep. 1991	Gulf	13.10	86.80	($213,475)	($27,965)	$176,594
Oct. 1991 - Mar. 1992	Gulf	3.40	96.60	$87,028	$2,959	$179,553
Apr. 1992 - Sep. 1992	Gulf	23.10	77.00	$322,504	$74,498	$254,051
Oct. 1992 - Mar. 1993	Gulf	4.60	95.50	$372,865	$17,152	$271,203
Apr. 1993 - Sep. 1993	Gulf	17.50	82.50	$128,552	$22,497	$293,700
Oct. 1993 - Mar. 1994	Gulf	15.00	85.00	($84,941)	($12,741)	$280,958
Apr. 1994 - Sep. 1994	Gulf	15.80	84.30	$22,931	$3,623	$284,581
Oct. 1994 - Mar. 1995	Gulf	10.90	41.00	$0	$0	$284,581
Apr. 1995 - Sept. 1995	Gulf	9.70	90.30	($483,077)	($46,858)	$237,723
Oct. 1995 - Mar. 1996	Gulf	3.30	54.20	($44,234)	($1,460)	$236,263
Apr. 1996 - Sept. 1996	Gulf	6.60	93.30	$82,198	$5,425	$241,688
Oct. 1996 - Mar. 1997	Gulf	3.20	96.60	$11,349	$363	$242,051
Apr. 1997 - Sept. 1997	Gulf	10.40	89.60	($300,745)	($31,277)	$210,774
Oct. 1997 - Mar. 1998	Gulf	3.90	96.10	$62,632	$2,443	$213,217
Apr. 1998 - Sept. 1998	Gulf	31.30	68.90	($75,355)	($23,586)	$189,631
Oct. 1998 - Dec. 1998	Gulf	22.90	77.10	$38,676	$8,857	$198,487
Jan. 1999 - Dec. 1999	Gulf	23.00	76.90	$183,842	$42,284	$240,771
Jan. 2000 - Dec. 2000	Gulf	26.70	73.20	$379,732	$101,388	$342,159
Jan. 2001 - Dec. 2001	Gulf	26.10	73.90	($369,498)	($96,439)	$245,720
Jan. 2002 - Dec. 2002	Gulf	33.20	66.80	$431,920	$143,397	$389,118
Jan. 2003 - Dec. 2003	Gulf	27.50	72.60	$625,280	$171,952	$561,070
Jan. 2004 - Dec. 2004	Gulf	24.20	75.70	$441,988	$106,961	$668,031
Jan. 2005 - Dec. 2005	Gulf	20.40	79.50	($842,874)	($171,946)	$496,085
Jan. 2006 - Dec. 2006	Gulf	18.12	81.88	($205,097)	($37,166)	$458,919
Jan. 2007 - Dec. 2007	Gulf	26.51	73.49	($690,892)	($183,165)	$275,754
Jan. 2008 - Dec. 2008	Gulf	18.51	81.45	$113,177	$20,947	$296,701
Jan. 2009 - Dec. 2009	Gulf	15.73	84.28	$257,966	$40,565	$337,266
Jan. 2010 - Dec. 2010	Gulf	9.94	90.07	$819,302	$81,418	$418,684
Jan. 2011 - Dec. 2011	Gulf	4.19	95.81	$1,040,660	$43,581	$462,265
Jan. 2012 - Dec. 2012	Gulf	8.00	92.00	$1,662,342	$132,987	$595,252

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 27th day of February, 2013.

Melissa A. Barnes

Notary Public, State of Florida at Large

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

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

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

Susan D. Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 5th day of March, 2013.

Melissa A. Darnes

Notary Public, State of Florida at Large

77

Gulf's Responses to Staff's Second Set of Interrogatories (Nos. 13-23)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 77
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0461-0478]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	)	Docket No. 130001-EI
		Date Filed: March 6, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SECOND SET OF INTERROGATORIES (NOS. 13-23)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Second Set of Interrogatories (Nos. 13-23) on the following pages.

Respectfully submitted by electronic mail the 6th day of March, 2013,

JEFFREY A. STONE
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Attorneys for Gulf Power Company

13. For each Request for Proposal (RFP) for coal issued in 2012 by Gulf Power Company (Gulf) for Plants Crist, Smith, and Daniel, list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

ANSWER:

A solicitation (RFP) was issued on February 6, 2012, soliciting bids from all suppliers contained in Southern Company's internet bid system which includes approved suppliers listed on the Gulf Power Company Bid List. The purchases were to be made for Plants Crist and Smith. Plants Scholz and Daniel had no uncommitted needs during this timeframe. The solicitation requested bids for the purchase of coal for a term of up to four (4) years beginning January 1, 2013 and ending on December 31, 2016. All bids were due on February 22, 2012. In response to the solicitation, twenty-five (25) bids were received from sixteen (16) different coal suppliers. The bids received consisted of twelve (12) Illinois Basin offers, seven (7) Central Appalachia offers, four (4) Western bituminous offers, one (1) Northern Appalachia offer and one (1) import offer from Colombia. The bids received included one, two, three and four year terms. Below is a listing of the bids that were received:

Bid	Supplier	TONS	YEAR	BTU/LB	%S	%ASH	%MOISTURE	TRANSPORT	DELV'D ($/MMBTU)
1	Foresight	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/Barge	[redacted]
2	Foresight	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/Barge	[redacted]
3	Interocean	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Barge	[redacted]
4	Foresight	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Barge	[redacted]
5	Foresight	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Barge	[redacted]
6	Mercuria	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/Barge	[redacted]

Bid	Supplier	TONS	YEAR	BTU/LB	%S	%ASH	%MOISTURE	TRANSPORT	DELV'D ($/MMBTU)
7	Sunrise	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
8	Peabody	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
9	Peabody	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
10	Oxbow	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
11	Patriot	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
12	White Oak	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
13	Lafayette	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
14	Arch	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
15	Arch	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
16	Alliance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
17	Alliance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Barge	[redacted]

Bid	Supplier	TONS	YEAR	BTU/LB	%S	%ASH	%MOISTURE	TRANSPORT	DELV'D ($/MMBTU)
18	Alliance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
19	TECO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
20	TECO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Barge	[redacted]
21	American	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
22	Alpha	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
23	Alpha	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
24	Consol	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Rail/barge	[redacted]
25	Argus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Barge	[redacted]

14. What action was taken for each bid identified in response to Interrogatory No. 1? Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

A review of Plants Crist and Smith's inventory plans and burn projections for 2013 through 2016 indicated a need to purchase coal at various volume levels. In evaluating the bids, Gulf typically groups purchases for Plants Crist and Smith together because of their common supply source and transportation mode. The goal of this RFP was to purchase volumes that conform to the contracting philosophy contained in the Gulf Power Company Long-Term Coal Procurement Strategy and Tactical Plan. The twenty-five (25) proposals received were evaluated on a fully delivered, net present value (NPV) basis, including the value of sulfur. In support of the evaluation process, transportation rates and SO_2 allowance values were provided and included as part of the analysis. Other inputs to the evaluation included railcar lease and maintenance costs where appropriate. In an effort to maintain the blend of 60% Illinois Basin high sulfur coal and 40% low sulfur coal that Plant Crist desires to burn, Gulf sought to purchase volumes along those guidelines.

High Sulfur Coal

The bids separated themselves based on delivered price, grouping the Illinois Basin offers together as the most economical coal delivered into Plant Crist and leaving the remaining, low sulfur offers to fall into place behind them. The least cost Illinois Basin offer was Bid No. 1 submitted by Foresight Coal Sales, LLC [redacted] This was a [redacted] year offer that delivered to Plant Crist for a starting price of [redacted] Gulf agreed to purchase [redacted] The next least cost offer was made by The American Coal Company, Bid No. 21. During negotiations and in response to Gulf's recent inventory management efforts, American agreed to defer [redacted] tons of coal from 2012 into 2013 in exchange for Gulf agreeing to purchase an additional [redacted] Additionally, American agreed to sell Gulf [redacted] tons of coal in 2014 [redacted] Gulf made the American coal purchase at a starting price delivered to Plant Crist of [redacted] Based on the then current burn projections, these purchased volumes conformed to the Gulf Power Company Long-Term Coal Procurement Strategy and Tactical Plan for the high sulfur supply.

Low Sulfur Coal

A short list of the most competitive low sulfur coal bids was also developed and suppliers who made the competitive tier were asked to revisit their bids and submit a modified bid by March 15, 2012. This was done in an effort to lower the total delivered cost of the blended product. For the re-bid prices, the lowest cost supplier, Argus Energy, bid on a one-year term and refused to modify their bid [redacted] As a result, Gulf purchased a one-year spot supply from them for [redacted] This coal was purchased for Plant Smith exclusively and delivered for [redacted] Alpha Natural Resource Partners submitted a modified bid by lowering their 2013 starting price from [redacted] which was acceptable to Gulf. Gulf purchased [redacted] a year for 2013 and 2014 from Alpha. The Alpha coal had a starting price delivered to Plant Crist of [redacted] These purchases completed Gulf's need for a blended product to be delivered to Plant Crist in conformance with Gulf Power Company's Long-Term Coal Procurement Strategy and Tactical Plan.

15. During 2012, did Gulf experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state charges by event.

ANSWER:

No.

16. For each RFP for natural gas issued in 2012 by Gulf, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

ANSWER:

Southern Company Services (SCS), as agent for Gulf Power Company, solicits bids for firm, baseload natural gas supply to assist in serving the fuel requirements of its generating plants. In order to qualify for consideration, all bids must contain 1) delivery point(s), 2) quantities, 3) term, and 4) pricing. The bids received from the Fall 2012 RFP are documented below.

Supplier: Apache
Volume and Pipeline: Annual Supply 5,000 per day Mobile Bay into All Delivery Points
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 5/14)

Supplier: BP
Volume and Pipeline: Summer Supply 50,000 per day into Florida Gas Transmission
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 9/13)

Supplier: BG
Volume and Pipeline: Annual Supply 8,000 per day Destin Pipeline into Florida Gas Transmission
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 5/18)
Volume and Pipeline: Annual Supply 20,000 per day Destin Pipeline into Florida Gas Transmission
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 5/18)
Volume and Pipeline: Summer Supply 15,000 per day Destin Pipeline into All Delivery Points
Price: FGT Z3 Gas Daily [redacted] (Term: June-Sept, 2013-2017)

Supplier: Chevron
Volume and Pipeline: Annual Supply 20,000 per day Mobile Bay into All Delivery Points
Price: FGT Zone 3 Gas Daily [redacted] (Term: 6/13 – 5/14)
Price: FGT Zone 3 Gas Daily [redacted] (Term: 6/13 – 5/15)
Volume and Pipeline: Annual Supply 8,000 per day Mobile Bay into All Delivery Points
Price: FGT Zone 3 Inside FERC [redacted] (Term: 6/13 – 5/14)
Price: FGT Zone 3 Inside FERC [redacted] (Term: 6/13 – 5/15)
Volume and Pipeline: Summer Supply 15,000 per day Destin into All Delivery Points
Price: FGT Zone 3 Gas Daily [redacted] (Term: 6/13 – 9/13)
Price: FGT Zone 3 Gas Daily [redacted] (Term: June-Sept, 2014-2015)

Supplier: Exxon
Volume and Pipeline: Annual Supply 8,000 per day Mobile Bay into All Delivery Points
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 5/14)
Volume and Pipeline: Annual Supply 15,000 per day Mobile Bay into All Delivery Points
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 5/14)

Supplier: Louie Dreyfus
Volume and Pipeline: Summer Supply 15,000 per day Destin into All Delivery Points
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 9/13)

Supplier: QEP
Volume and Pipeline: Annual Supply 8,000 per day Mobile Bay into GSPL/FGT Airport
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 5/14)

Supplier: Shell
Volume and Pipeline: Summer Supply 10,000 per day Destin into All Delivery Points
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 9/13)

Supplier: Tenaska
Volume and Pipeline: Summer Supply 15,000 per day Destin into All Delivery Points
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 9/13)

Supplier: WPX Energy
Volume and Pipeline: Annual Supply 10,000 per day Mobile Bay into FGT, MGS Gulfstream
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 5/14)
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 5/14)

17. What action was taken for each bid identified in response to Interrogatory No. 16? Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

After reviewing the gas supply needs, each bid was evaluated based on price, location, volume, term, transportation rights (firm or interruptible) and the flexibility of supply. The selected bids that met the needed volume and term are as follows:

Supplier: Exxon
Volume and Pipeline: Annual Supply 8,000 per day Mobile Bay into All Delivery Points
Price: FGT Z3 Inside FERC [redacted] (Term: 6/13 – 5/14)
Volume and Pipeline: Annual Supply 15,000 per day Mobile Bay into All Delivery Points
Price: FGT Z3 Gas Daily [redacted] (Term: 6/13 – 5/14)

18. In 2012, did Gulf participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response.

ANSWER:

Southern Company Services (SCS), as agent for Gulf Power, participated in an open season solicitation on Gulf South Pipeline for additional firm transportation to Plant Crist. Firm transportation capacity of 15,000 MMBTU/day was contracted on Gulf South Pipeline to support the gas needs of Plant Crist starting on April 1, 2015.

19. In 2012, did Gulf participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

ANSWER:

During 2012, Gulf arranged for 1.3 BCF of gas storage capacity at the Leaf River Energy Center that was under contract by other operating companies of the Southern Company to be allocated to Gulf over the term of 4/1/2013 –5/31/2023. This allocation was executed to provide more operational flexibility at the Central Alabama PPA and add natural gas inventory for this generating resource in lieu of additional oil inventory given the greater expense of using fuel oil as a backup fuel. The 1.3 BCF allocation of gas storage capacity represents approximately 10 days of storage supply to support the 130,000 MMBTU of Central Alabama Firm Gas Transportation.

20. For each RFP for light oil issued in 2012 by Gulf, list the bids received.

ANSWER:

A solicitation (RFP) was issued on December 12, 2012, soliciting bids from 28 known suppliers capable of providing fuel oil requirements for Gulf Power's Plants Crist, Scholz and Smith as well as for the Purchase Power Agreement (PPA) plants at the Coral Baconton facility located in Baconton, GA and the Tenaska Central Alabama facility located in Billingsly, AL. The solicitation requested bids for the fuel oil requirements for one year; the period March 1, 2013 through February 28, 2014. In response to the solicitation, bids were received by the required date of January 15, 2013 from 11 of the 28 potential suppliers as noted in the chart below. These offers are in the form of a dollar per gallon adder to the daily OPIS index for dyed ultra low sulfur diesel to derive a delivered price per gallon Gulf Power will pay for fuel oil on a specific shipment date.

2013/2014 Gulf Power Fuel Oil Bid Results
Dollar per gallon adder to daily OPID index price

Supplier	Baconton	Crist	Scholz	Smith	Tenaska, AL
Retif	NB	[redacted]	[redacted]	[redacted]	NB
Pilot	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TAC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RKA	NB	NB	NB	NB	NB
Boswell	NB	[redacted]	[redacted]	[redacted]	NB
Mansfield	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mcherson	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PS Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pet Traders	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Indigo	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lanier	[redacted]	NB	NB	NB	NB

21. What action was taken for each bid identified in response to Interrogatory No. 20? Include in your response an explanation of the evaluation process and how successful proposals were selected.

ANSWER:

Bids were opened, recorded and reviewed to insure there were no exceptions taken by the suppliers to Gulf Power's Terms and Conditions and that all bids were signed appropriately by a supplier representative. SCS Fuel Services recommended to Gulf Power that for the five plant locations the low bidder, based on delivered price, be issued a purchase order agreement for the subsequent annual period. All four suppliers selected are companies that Southern Company has previously done business with successfully. Gulf Power agreed and purchase order agreements for the annual term were issued as follows:

Plant	Supplier	PO Number	
Baconton	TAC	GO1201	(Extended by Change order #1)
Crist	Mansfield	GO1301	
Scholz	Boswell	GO1302	
Smith	Boswell	GO1303	
Tenaska, AL	PS Energy	GO1304	

22. Please describe Gulf's process for purchasing power on a long-term contractual basis including how it solicits and communicates with suppliers and how it negotiates supply contracts and transmission arrangements. Exclude Interchange contract transactions.

ANSWER:

As a participant in the Southern electric system Integrated Resource Planning process, Gulf identifies the type and timing of its next generation capacity addition. Before constructing a planned generating unit(s) subject to the Power Plant Siting Act, Gulf would issue a Request for Proposals (RFP) in accordance with FPSC Rule 25-22.082 in order to evaluate capacity resource alternatives to its self-build generation option.

The FPSC solicitation process directs Gulf to notify the market of its intentions to issue an RFP by publishing public notices in state and national publications such as newspapers, periodicals, and trade publications. All proposals received in response to Gulf's RFP are evaluated and ranked based on price and non-price attributes. The respondent with the best proposal is ultimately determined and notified that they have been selected for negotiation of a power purchase agreement. Any transmission arrangements needed for delivery of the seller's capacity and energy to Gulf's system is not negotiated. Rather, transmission service is secured by executing service agreements per the terms and conditions contained in the transmission provider's tariffs that are filed with the Federal Energy Regulatory Commission.

23. For each purchased power supply contract that Gulf executed in 2012, describe the process that led to this contract. Include the supplier, volume, and delivered price information, as well as the transmission arrangements. Exclude Interchange contract transactions.

ANSWER:

N/A

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 5th day of March, 2013.

Melissa A. Darnes
Notary Public, State of Florida at Large

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

78

Gulf's Responses to Staff's Third Set of Interrogatories (Nos. 24-34)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 78
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0479-0497]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 130001-EI Date Filed: March 21, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S THIRD SET OF INTERROGATORIES (NOS. 24-34)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Third Set of Interrogatories (Nos. 24-34) on the following pages.

Respectfully submitted by electronic mail the 21st day of March, 2013,

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Attorneys for Gulf Power Company

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

24. Please state whether performance improvement in availability and heat rate also increases the company's ability or opportunity to make off-system economy sales. As part of the response, please provide the MWh and dollar amounts of off-system economy sales by year for 2006 through 2012.

ANSWER:

Heat rate and availability are factors that can affect Gulf's ability to make off system economy sales. However, an improvement in these performance measures cannot be directly correlated to the amount of sales made due to the variable nature of these sales.

Improvement in heat rate would lower the economic dispatch cost of the unit in question and make it more likely to be dispatched to serve load at any point in time. Improvement in availability would make it more likely that a specific generating unit would be available to economically serve load at any point in time if called upon. In general, economy sales are a function of the needs of the off system customer, system load levels at the time an off-system economy sales opportunity arises, and which generating units would be economically dispatched to serve those loads at that point in time.

Off-system Economy Sales

Year	Sale MWh	Sales Revenue
2006	257,019	$ 14,321,387
2007	223,114	$ 12,546,516
2008	129,169	$ 9,731,069
2009	64,694	$ 3,684,445
2010	62,532	$ 3,744,074
2011	43,272	$ 2,540,120
2012	92,577	$ 3,702,078

25. Please state whether performance degradation in availability and heat rate also increases the company's ability or opportunity to make off-system economy purchases? As part of the response, please provide the MWh and dollar amounts of off-system economy purchases by year for 2006 through 2012.

ANSWER:

As in the case of sales, heat rate and availability are also factors that can affect Gulf's ability or opportunity to make off-system economy purchases, but degradation of these performance measures cannot be directly correlated to an amount of purchases made due to the variable nature of these purchases. Degraded heat rates and availabilities of Gulf units could increase the ability or opportunity to purchase energy from the most economical resource. This energy may be from a Southern system unit or an off-system resource depending on the economics of market energy as compared to system energy and the level of system loads at any point in time.

Off-system Economy Purchases

Year	Purchase MWh	Purchase Cost
2006	280,581	$ 16,104,187
2007	167,964	$ 10,770,725
2008	435,829	$ 26,649,211
2009	217,826	$ 7,532,658
2010	163,417	$ 7,790,894
2011	159,894	$ 5,891,316
2012	194,315	$ 5,214,629

26. Please provide the data in the following table.

ANSWER

Year	GPIF Total Points[b]	GPIF Reward / Penalty[b] ($)	System Fuel Cost at Target Level of Performance[a]	System Fuel Cost at Actual Level of Performance[a]	GPIF Fuel Savings / Costs[b] ($)
2006	-0.84	(205,097)	$498,744,399	$482,566,030	(776,160)
2007	-2.83	(690,892)	$548,174,830	$517,755,767	(3,911,890)
2008	0.36	113,177	$597,348,987	$597,349,815	377,280
2009	0.69	257,966	$776,735,741	$458,291,108	1,085,370
2010	1.98	819,302	$642,754,876	$609,431,630	3,165,040
2011	2.38	1,040,660	$621,972,069	$499,058,778	3,052,160
2012	3.62	1,497,916	$544,329,207	$336,230,455	4,900,480

Notes:

a System Fuel cost at Target level was taken from the Projected Fuel Filing Schedule E-4 column (l) subtracting Scherer 3 and Other Generation from the total. System Fuel Cost at Actual level was taken from the Operating Report Schedule 21a summing the entire Gulf owned plants, PPAs are not included.

b GPIF total points and Reward/Penalty numbers were taken from the yearly results filing and the Fuel Savings/Costs were interpolated using the data found on Page 3 of Schedule 5 of the yearly GPIF Results Filing.

27. Please provide the data in the following table.

ANSWER:

Year	Total EAF Points[b]	EAF Reward / Penalty[b] ($)	System Fuel Cost at Target Level of EAF Performance[a]	System Fuel Cost at Actual Level of EAF Performance[a]	Fuel Savings / Costs due to EAF[b] ($)
2006	1.32	(37,166)	$498,744,399	$482,566,030	1,089,000
2007	0.29	(183,165)	$548,174,830	$517,755,767	347,420
2008	0.60	20,947	$597,348,987	$597,349,815	628,800
2009	0.16	40,565	$776,735,741	$458,291,108	251,680
2010	0.67	81,418	$642,754,876	$609,431,630	1,071,330
2011	0.09	43,581	$621,972,069	$499,058,778	115,380
2012	0.17	119,833	$544,329,207	$336,230,455	230,180

Notes

a. The same fuel costs as provided in response to interrogatory no. 26. There is no System Fuel Cost Target or System Fuel Cost Actual associated with EAF.

b. Total EAF points were taken from the yearly GPIF Results filing using the data from Page 2 of Schedule 4. The EAF Reward/Penalty was calculated as in Staff's first set of Interrogatories answer to 12(f) using the EAF weighting multiplied times the entire GPIF reward/penalty. This is the reason for the incongruity in 2006 and 2007. EAF Fuel Savings/Costs were interpolated using the data found on Page 3 of Schedule 5 of the yearly GPIF Results Filing.

28. Please provide the EFOR (Equivalent Forced Outage Rate) data for each GPIF unit by year for 2006 through 2012.

ANSWER:

EFOR	2006	2007	2008	2009	2010	2011	2012
Crist 4	0.25	0.53	0.90	0.36	1.22	0.00	0.50
Crist 5	0.02	0.93	1.09	0.44	0.85	0.21	0.02
Crist 6	2.53	1.84	7.35	1.77	3.93	3.47	1.58
Crist 7	1.96	6.69	3.68	5.91	4.63	1.08	1.08
Smith 1	3.55	0.34	0.16	3.42	1.65	0.76	1.15
Smith 2	4.52	0.43	2.98	0.27	0.95	0.47	0.04
Daniel 1	0.71	0.29	12.96	0.23	4.38	3.92	0.99
Daniel 2	4.15	1.95	4.02	2.26	0.74	2.88	0.71

29. Please describe the method of estimating the maximum fuel savings reported in Gulf's GPIF projection and actual filings. As part of the response, please identify the source and reasoning for the use of the production simulation model for the actual filings.

ANSWER:

Gulf uses the PROSYM Energy and FUELPRO models to estimate the maximum fuel savings in Gulf's GPIF Target filing. The PROSYM Energy model uses the load forecast and operational data for the forecast year. The model economically dispatches the units and outputs the monthly generation and BTUs for each unit for the Southern electric system. The BTU files for the units are then used in a second modeling program FUELPRO to calculate the fuel costs based on the fuel pricing and usage throughout the year. The fuel savings are based on changes to the inputs portion of the PROSYM Energy Dispatch model which changes the BTUs for the unit, therefore changing the fuel cost for that period.

30. Please provide a comparison of the projected and actual monthly fuel cost for 2012 and factors contributing to the difference. As part of the response, please provide the data and calculations supporting the following:

a) Difference in average monthly heat rates for the aggregated GPIF units,
b) Difference in average monthly heat rates for the system (including non-GPIF units),
c) Difference in average monthly fuel price ($/mmBtu) for the aggregated GPIF units,
d) Difference in average monthly fuel price ($/mmBtu) for the system (including non-GPIF units),
e) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model,
f) Difference in monthly fuel cost dollars for the system (including non-GPIF units), caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model,
g) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model, and
h) Difference in monthly fuel cost dollars for system (including non-GPIF units), caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model.

ANSWER:

a. See Gulf's Response to 30(a) on Attachment A page 1 of 2.

b. See Gulf's Response to 30(b) on Attachment B page 2 of 2.

c. The projected average coal price was projected to be $4.23 per MMBTU. The actual average coal price was $4.64 per MMBTU which is $0.41 per MMBTU or 9.69% above the projected amount.

d. The projected average monthly fuel price for 2012 was $4.23 per MMBTU. The actual average monthly fuel price for 2012 was $4.28 per MMBTU which is $0.05 per MMBTU or 1.18% above the projected amount.

Coal price was projected to be $4.23 per MMBTU. The actual average coal price was $4.64 per MMBTU which is $0.41 per MMBTU or 9.69% above the projected amount. Natural gas price was projected to be $4.22 per MMBTU. The actual natural gas price was $3.71 per MMBTU which is $0.51 or 12.09% below the projected amount. The lower than projected natural gas price is due to a significant drop in the market price of natural gas in 2012. Market prices were lower due to gas supply exceeding demand during the period. Much of Gulf's natural gas purchases are made at market price for the day the gas is supplied. The quantity of fuel consumed by type was also more heavily weighted to natural gas than projected. Natural gas burn was projected to be 27,540,901 MMBTU or 26.9% of the total projected fuel burn of 102,359,831 MMBTU. Actual natural gas burn was 30,223,877 MMBTU or 39.1% of the total actual fuel burn of 77,238,446 MMBTU.

The combination of natural gas being 12.25% lower in price and making up a higher percentage of the fuel burn mix resulted in a lower total average fuel price for 2012.

Difference in Average Monthly Fuel Price

Month	Actual ($/mmBtu)	Estimated ($/mmBtu)	Difference
January	4.25	4.80	(.55)
February	3.89	4.75	(.86)
March	3.61	4.58	(.97)
April	3.82	4.80	(.98)
May	4.24	4.63	(.39)
June	4.53	4.59	(.06)
July	4.49	3.56	.93
August	4.67	3.62	1.05
September	4.36	3.55	.81
October	4.62	4.13	.49
November	4.60	3.59	1.01
December	4.17	3.54	.63

e. The projected total fuel cost of net generation for 2012 was $435,601,965. The actual fuel cost of net generation was $334,006,797 which is $101,595,168 or 23.32% below the projected amount. The variance between projected and actual total fuel cost dollars are determined by many factors that are outside the company's control. Some of these are:

- The market price of fuel, primarily coal and natural gas.
- Fuel quality constraints for operational and/or environmental reasons that limit the fuel choices and price competition between available fuel choices in the entire marketplace.
- Economic dispatch of units within the Southern Company pool driven primarily by marginal replacement fuel costs.
- Customer energy demand driven primarily by weather.
- External sales of energy that is driven both by external customer demand and the availability and marginal dispatch cost of Gulf's generating units relative to an alternative market energy supply.

The impact of these various outside factors on fuel costs are difficult to quantify and isolate and are interrelated. Therefore, calculating of the dollar difference caused by each factor cannot readily be determined.

f. See Gulf's Responses to item 30(e).

g. The variance between projected and actual total fuel cost dollars are influenced by many factors that are within the company's control. Some of these are:

- The fuel procurement process and contracting strategy.
- Generating unit availability results directly influenced by plant operating and maintenance strategy and execution.
- Heat rate performance directly influenced by plant operating and maintenance strategy and execution.

The impact of these various factors within the company's operational control on fuel costs is difficult to quantify and isolate and they tend to be interrelated to some degree. These factors can also be influenced by factors that are outside the company's operational control. An example would be the

impact of changing loads on generating units' heat rate. Generating units operate less efficiently at lower loads and more efficiently at the unit's normal full loading. If unit load is lower than projected due to changes in unit dispatch from either customer demand or unit economics, the heat rate of that unit will be higher (less efficient) than projected. It may not be possible to determine whether factors outside or within in the company's control would be the primary driver of unit heat rate in this case. Therefore, calculation of the impact on fuel costs caused by each factor cannot readily be determined even with the use of a production simulation model.

h. See Gulf's Responses to item 30(g).

ROG 30 (a)

2012 GPIF

Target	January	February	March	April	May	June	July	August	September	October	November	December
Crist 4	11,741	11,827	11,827	11,502	11,336	11,205	11,615	11,149	11,260	11,432	11,314	11,767
Crist 5	11,694	11,744	11,806	11,195	11,306	11,119	11,344	11,392	11,575	11,364	11,638	11,686
Crist 6	11,648	11,747	0	11,554	11,324	11,134	11,060	11,321	11,491	12,230	11,308	11,732
Crist 7	10,415	10,482	10,727	10,980	10,658	10,652	10,655	10,653	10,835	10,421	0	10,844
Smith 1	10,580	10,580	10,581	10,583	10,784	10,696	10,663	10,572	10,756	10,603	10,597	10,580
Smith 2	10,836	10,593	10,606	10,608	10,448	10,549	10,466	10,464	10,626	10,351	10,456	10,583
Daniel 1	11,272	11,146	10,872	10,648	10,555	10,492	10,614	10,418	10,602	10,753	11,037	10,968
Daniel 2	10,416	11,000	10,912	10,714	10,614	10,560	10,334	10,478	10,422	10,486	10,983	10,953

2012GPIF

Actual	January	February	March	April	May	June	July	August	September	October	November	December
Crist 4	12,754	0	12,028	12,117	0	11,325	0	0	0	0	11,763	11,194
Crist 5	10,846	11,198	11,958	11,684	10,747	12,039	11,600	11,122	10,512	11,859	11,435	0
Crist 6	11,889	0	0	12,198	10,255	10,349	10,460	11,577	10,755	10,798	10,822	10,476
Crist 7	11,435	11,402	11,360	11,685	12,033	11,016	11,383	10,860	0	0	0	11,728
Smith 1	10,774	10,762	10,745	10,701	10,616	10,750	10,804	11,032	11,047	0	10,795	10,826
Smith 2	0	0	0	10,500	10,723	0	11,189	11,445	11,462	11,236	10,962	0
Daniel 1	10,191	0	9,834	0	10,978	10,078	10,274	11,183	0	11,653	10,127	0
Daniel 2	9,876	0	10,297	9,985	10,893	10,460	10,978	11,221	0	0	0	0

The main difference in Target vs. Actual heat rate is in the difference in generation on the coal units. You can see comparing the Target vs. the Actual that many of the months the units were forecasted to run, but were on reserve shutdown indicated by 0. When the units were on-line they were not fully loaded and were at a different place on the target heat rate curve which resulted in a higher heat rate than forecasted. This change in forecast was primarily due to natural gas prices and how much generation Smith 3 and other gas powered combined cycle units provided in the Southern system due to economic dispatch.

Staff's Third Set of Interrogatories
Docket No. 130001-EI
GULF POWER COMPANY
March 21, 2013
Item 30
Attachment A, Page 1 of 2

ROG 30 (b)

2012 System

Target	January	February	March	April	May	June	July	August	September	October	November	December
Crist 4	11,741	11,827	11,827	11,502	11,336	11,205	11,615	11,149	11,260	11,432	11,314	11,767
Crist 5	11,694	11,744	11,806	11,195	11,306	11,119	11,344	11,392	11,575	11,364	11,638	11,686
Crist 6	11,648	11,747	0	11,554	11,324	11,134	11,060	11,321	11,491	12,230	11,308	11,732
Crist 7	10,415	10,482	10,727	10,980	10,658	10,652	10,655	10,653	10,835	10,421	0	10,844
Smith 1	10,580	10,580	10,581	10,583	10,784	10,696	10,663	10,572	10,756	10,603	10,597	10,580
Smith 2	10,836	10,593	10,606	10,608	10,448	10,549	10,466	10,464	10,626	10,351	10,456	10,583
Scholz 1	12,475	12,475	0	0	0	0	0	12,475	0	0	0	0
Scholz 2	12,938	0	0	0	0	0	0	12,938	0	0	0	0
Smith 3	7,036	7,062	7,049	7,117	7,239	7,222	7,210	7,218	7,196	7,111	7,064	7,012
Daniel 1	11,272	11,146	10,872	10,648	10,555	10,492	10,614	10,418	10,602	10,753	11,037	10,968
Daniel 2	10,416	11,000	10,912	10,714	10,614	10,560	10,334	10,478	10,422	10,486	10,983	10,953

2012 System

Actual	January	February	March	April	May	June	July	August	September	October	November	December
Crist 4	12,754	0	12,028	12,117	0	11,325	0	0	0	0	11,763	11,194
Crist 5	10,846	11,198	11,958	11,684	10,747	12,039	11,600	11,122	10,512	11,859	11,435	0
Crist 6	11,889	0	0	12,198	10,255	10,349	10,460	11,577	10,755	10,798	10,822	10,476
Crist 7	11,435	11,402	11,360	11,685	12,033	11,016	11,383	10,860	0	0	0	11,728
Smith 1	10,774	10,762	10,745	10,701	10,616	10,750	10,804	11,032	11,047	0	10,795	10,826
Smith 2	0	0	0	10,500	10,723	0	11,189	11,445	11,462	11,236	10,962	0
Scholz 1	0	0	0	0	0	0	14,274	0	0	0	0	0
Scholz 2	0	0	0	0	0	0	14,422	0	0	0	0	0
Smith 3	6,847	6,779	6,823	6,982	6,938	7,277	7,348	7,280	6,866	6,929	6,896	6,899
Daniel 1	10,191	0	9,834	0	10,978	10,078	10,274	11,183	0	11,653	10,127	0
Daniel 2	9,876	0	10,297	9,985	10,893	10,460	10,978	11,221	0	0	0	0

The main difference in Target vs. Actual heat rate is in the difference in generation on the coal units. You can see comparing the Target vs. the Actual that many of the months the units were forecasted to run, but were on reserve shutdown indicated by 0. When the units were on-line they were not fully loaded and were at a different place on the target heat rate curve which resulted in a higher heat rate than forecasted. This change in forecast was primarily due to natural gas prices and how much generation Smith 3 and other gas powered combined cycle units provided in the Southern system due to economic dispatch.

Staff's Third Set of Interrogatories
Docket No. 130001-EI
GULF POWER COMPANY
March 21, 2013
Item 30
Attachment A, Page 2 of 2

31. Please state the manner in which the GPIF mechanism may be modified to achieve the same fuel savings and efficiency objective that will allow fuel savings to be calculated and verified without the use of production simulation model.

ANSWER:

Gulf does not advocate changing the GPIF mechanism. The system forecasting models and resulting fuel costs are the most accurate tools available. We are not aware of an accurate approach outside of what is used for the GPIF mechanism.

32. Please state the manner in which your company sets performance expectations for individual unit production efficiency, measures performance against expectations, and calibrates incentives for management accountability for the individual plant.

ANSWER:

Power generation performance goals are comprised of five major components. The components are safety, people, reliability, cost and compliance. Production efficiency goals are contained within the reliability and cost components. The reliability goals are Peak Season Equivalent Forced Outage Rate (PEFOR) and Annual Equivalent Unplanned Unavailability Factor (EUUF). A portion of the cost component goal is heat rate. Each generating unit has a goal in the specific area based on the past year's performance in these areas. The expectation for management is to meet or exceed the goals. The generating unit goals are aggregated to a plant goal and the plant goals roll up to a system goal.

33. Describe the manner in which your company sets performance expectations for total system production efficiency, measures performance against expectations, and calibrates incentives for management accountable for the total system.

ANSWER:

See Gulf's Response to item 32.

34. Describe the manner in which your company evaluates the effectiveness of its incentive mechanism, makes improvement in the mechanism, and promotes sharing best practices that improve production efficiency?

ANSWER:

The Company goals are based on a five level system. The target level is Level 3, Level 1 is the lowest level of performance and Level 5 is the highest. The target level is generally based on past performance and expectations are to improve performance to at least Level 3. Generally, normal wear on a generating unit over time causes performance degradation. Thus, achieving or exceeding the Level 3 goal presents a challenge to the plant.

Best practices are shared through system owners, performance engineers and management forums that bring like-minded employees together both electronically and face to face.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 19th day of March, 2013.

Melissa A. Darnes
Notary Public, State of Florida at Large

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

79

Gulf's Responses to Staff's Fourth Set of Interrogatories (No. 35)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 79
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0498-0501]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 130001-EI Date Filed: April 26, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 35-36)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Fourth Set of Interrogatories (Nos. 35-36) on the following pages.

Respectfully submitted by electronic mail this 26th day of April, 2013,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

35. On Page 7, Line 13 of Gulf witness H. R. Ball's Direct Testimony filed on March 1, 2013, the witness states that Gulf had a "carryover of contract coal tons from the previous year."
    a) Is 2011 the year the witness is referring to as the "previous year?" If not, please specify.
    b) Did Gulf take delivery of all coal from the "carryover" contracts in 2012? If not, please specify, by vendor and quantity, that which was not delivered.
    c) Were any fees or costs incurred (directly or indirectly) related to the deferred coal shipments? If so, please list each deferment and the fee or cost incurred, by date and vendor.

ANSWER:

a. Yes.

b. Yes.

c. No.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 25th day of April, 2013.

Melissa A. Darnes
Notary Public, State of Florida at Large

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

80

Gulf's Responses to Staff's Fifth Set of Interrogatories (Nos. 37-38)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 80
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0502-0506]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 130001-EI Date Filed: May 29, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 37-38)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Fifth Set of Interrogatories (Nos. 37-38) on the following pages.

Respectfully submitted by electronic mail this 29th day of May, 2013,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
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(850) 432-2451
Attorneys for Gulf Power Company

Interrogatory Nos. 37-38 are in regard to the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

37. Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) tables in the actual filings for each year during the period from 2006 through 2012.

ANSWER:

GPIF Results Filing		**Fuel** (000's)		**GPIF Incentive** (000's)	
Period		Max Savings	Max Loss	Max Reward	Max Penalty
Jan. 2006 – Dec. 2006	Gulf	$ 8,250	$ 9,244	$2,442	$2,442
Jan. 2007 – Dec. 2007	Gulf	$11,976	$13,822	$2,798	$2,798
Jan. 2008 – Dec. 2008	Gulf	$10,482	$11,588	$3,144	$3,144
Jan. 2009 – Dec. 2009	Gulf	$15,734	$17,200	$3,739	$3,739
Jan. 2010 – Dec. 2010	Gulf	$15,987	$17,014	$4,138	$4,138
Jan. 2011 – Dec. 2011	Gulf	$12,823	$13,037	$4,373	$4,373
Jan. 2012 – Dec. 2012	Gulf	$13,538	$13,963	$4,592	$4,592

38. Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the projection filings for each year during the period from 2006 through 2012. If the amounts are different from the ones contained in the actual filings, please explain.

ANSWER:

The GPIF Incentive reward/penalty is different between the Target Filing and Results Filing since the Target is based on projected common equity and revenue at the time of the Target Filing and the Results Filing is based on the actual common equity and revenues for the period.

GPIF Target Filing		**Fuel (000's)**		**GPIF Incentive (000's)**	
Period		Max Savings	Max Loss	Max Reward	Max Penalty
Jan. 2006 – Dec. 2006	Gulf	$ 8,250	$ 9,244	$2,402	$2,402
Jan. 2007 – Dec. 2007	Gulf	$11,976	$13,822	$2,746	$2,746
Jan. 2008 – Dec. 2008	Gulf	$10,482	$11,588	$3,354	$3,354
Jan. 2009 – Dec. 2009	Gulf	$15,734	$17,200	$3,641	$3,641
Jan. 2010 – Dec. 2010	Gulf	$15,987	$17,014	$4,181	$4,181
Jan. 2011 – Dec. 2011	Gulf	$12,823	$13,037	$4,338	$4,338
Jan. 2012 – Dec. 2012	Gulf	$13,538	$13,963	$4,637	$4,637

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 28th day of May, 2013.

Notary Public, State of Florida at Large

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

81

Gulf's Responses to Staff's Sixth Set of Interrogatories (Nos. 39-47)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 81
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0507-0518]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)	Docket No. 130001-EI Date Filed: August 9, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 39-47)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Sixth Set of Interrogatories (Nos. 39-47) on the following pages.

Respectfully submitted by electronic mail this 9th day of August, 2013,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 39-46.

39. Describe the manner in which Gulf applied the formulaic representation at Original Sheet No. 3.400 where a provision limits the maximum allowed incentive dollars. As part of the response, please describe whether Gulf's application of this provision, if any, has been changed by Commission orders since the inception of the GPIF, including the stipulation by Order No. 18136 in Docket No. 870001-EI.

ANSWER:

Gulf Power calculates the maximum incentive dollars as set forth in Original sheet No. 3.400. As the GPIF has moved to an annual basis the Average Jurisdictional Common Equity is based on the calendar year and therefore uses a 12 month average. The maximum incentive calculated by the original method is then reduced by the Jurisdictional Separation Factor which is the ratio of Jurisdictional kWh sales divided by Total Territorial kWh sales.

40. Have the maximum allowed incentive dollars ever exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of your company's GPIF projection or actual filings in the period of 2005 through 2012? If so, please provide the year and the reasons.

ANSWER:

No. The GPIF reward/penalty has not exceeded 50 percent of the fuel savings/loss in the period 2005 through 2012.

41. Describe whether the linear scale and interpolation used by Gulf in its reward (penalty) tables is based on data supporting the linear relationship or the need for simplicity. If applicable, please provide data that demonstrate the relationship between the performance levels and fuel savings.

ANSWER:

The reward/penalty tables are linear based on the 1-10 points and therefore should remain linear for simplicity. The point's calculations for each unit are weighted based on the units' projected or actual performance.

42. Based on the use of linear interpolation, should the reward (penalty) be capped at 50 percent of the fuel savings corresponding to the actual performance level in the reward (penalty) table by setting the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings? If not, please explain.

ANSWER:

While Gulf does not believe any revisions to the current GPIF mechanism are necessary, it would not be opposed to modifications to how rewards or penalties are calculated as long as the modifications are symmetrical. Thus, Gulf would be agreeable to setting the maximum reward/penalty at 50 percent of the fuel savings/loss and using a linear interpolation of the reward/penalty.

43. Should the existing minimum heat rate threshold of 75 Btu/kWh be modified, with a different number or a percentage based on the unit efficiency? As part of the response, please provide the data and analysis supporting your response.

ANSWER:

Gulf does not see the need to change the existing minimum heat rate threshold of 75 BTU/kWh.

44. Should there be a similar minimum availability performance threshold for the GPIF reward (penalty)? As part of the response, please provide the data and analysis supporting your response.

ANSWER:

Gulf does not see the need to add a minimum availability performance threshold.

45. Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? As part of the response, please provide the data and analysis supporting your response.

ANSWER:

Gulf does not believe any modifications to the reward/penalty cap or the minimum threshold is necessary to improve the effectiveness of the GPIF.

46. Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? If so, provide data and analysis supporting such modification.

ANSWER:

Please see Gulf's response to Interrogatory No. 45.

For the following question, please refer to Gulf's response to Staff's Interrogatory No. 26 for the 2007 GPIF penalty amount and Page 30 of Order No. PSC-08-0824-FOF-EI in Docket No. 080001-EI.

47. Please explain the difference between the $433,685 GPIF penalty based on the order and the $690,682 penalty based on the interrogatory response.

ANSWER:

The amount ($690,682) provided in the response to Interrogatory No.26 is incorrect. The correct GPIF Penalty amount for 2007 is $$433,685 as presented on page 30 of Order No. PSC-08-0824-FOF-EI.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 8th day of August, 2013.

Melissa A. Barnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA

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

82

Gulf's Responses to Staff's Seventh Set of Interrogatories (Nos. 48-59)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 82
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0519-0538]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)		Docket No. 130001-EI Date Filed: October 17, 2013

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SEVENTH SET OF INTERROGATORIES (NOS. 48-59)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Seventh Set of Interrogatories (Nos. 48-59) on the following pages.

Respectfully submitted by electronic mail this 17th day of October, 2013,

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
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Attorneys for Gulf Power Company

48. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for natural gas, please provide the following information in a schedule format:
(a) the transaction date (the date the swap was entered into) for the swap;
(b) the fixed price for the swap;
(c) the month or period in the future the swap is covering; and
(d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

ANSWER:

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
1	1/8/2009	[redacted]	2/1/2012	12/1/2012	7.222	[redacted]
2	1/14/2009		2/1/2012	12/1/2012	7.162	
3	1/23/2009		3/1/2012	12/1/2012	7.002	
4	3/4/2009		4/1/2012	10/1/2012	6.501	
5	6/22/2009		4/1/2012	10/1/2012	6.881	
6	7/13/2009		1/1/2013	12/1/2013	6.935	
7	7/15/2009		4/1/2012	10/1/2012	6.493	
8	8/31/2009		1/1/2013	12/1/2013	6.896	
9	9/3/2009		1/1/2013	12/1/2013	6.747	
10	3/23/2010		4/1/2012	10/1/2012	5.620	
11	8/16/2010		4/1/2012	10/1/2012	5.157	
12	8/26/2010		1/1/2011	12/1/2012	4.969	
13	9/16/2010		1/1/2013	12/1/2013	5.496	
14	9/17/2010		1/1/2012	12/1/2012	5.188	
15	9/21/2010		1/1/2012	12/1/2012	5.086	
16	9/21/2010		1/1/2011	12/1/2012	4.624	
17	11/5/2010		1/1/2012	12/1/2012	4.991	
18	12/16/2010		1/1/2012	12/1/2012	4.879	
19	1/5/2011		1/1/2013	12/1/2013	5.236	
20	1/27/2011		1/1/2012	12/1/2012	4.940	

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
21	2/7/2011	[redacted]	1/1/2012	12/1/2012	4.878	[redacted]
22	2/9/2011	[redacted]	1/1/2012	12/1/2012	4.827	[redacted]
23	2/16/2011	[redacted]	1/1/2012	12/1/2012	4.709	[redacted]
24	2/17/2011	[redacted]	1/1/2012	12/1/2012	4.707	[redacted]
25	2/23/2011	[redacted]	1/1/2013	12/1/2013	5.126	[redacted]
26	3/2/2011	[redacted]	1/1/2012	12/1/2012	4.713	[redacted]
27	3/10/2011	[redacted]	1/1/2012	12/1/2012	4.725	[redacted]
28	4/5/2011	[redacted]	1/1/2013	12/1/2013	5.369	[redacted]
29	4/6/2011	[redacted]	1/1/2012	12/1/2012	4.932	[redacted]
30	4/18/2011	[redacted]	1/1/2012	12/1/2012	4.868	[redacted]
31	4/18/2011	[redacted]	1/1/2013	12/1/2013	5.281	[redacted]
32	5/5/2011	[redacted]	1/1/2013	12/1/2013	5.287	[redacted]
33	5/5/2011	[redacted]	1/1/2012	12/1/2012	4.899	[redacted]
34	5/9/2011	[redacted]	1/1/2013	12/1/2013	5.217	[redacted]
35	5/17/2011	[redacted]	1/1/2012	12/1/2012	4.868	[redacted]
36	5/26/2011	[redacted]	1/1/2013	12/1/2013	5.266	[redacted]
37	6/3/2011	[redacted]	1/1/2013	12/1/2013	5.333	[redacted]
38	6/23/2011	[redacted]	1/1/2012	12/1/2012	4.698	[redacted]
39	6/27/2011	[redacted]	1/1/2012	12/1/2012	4.721	[redacted]
40	7/6/2011	[redacted]	1/1/2013	12/1/2013	5.087	[redacted]
41	7/6/2011	[redacted]	1/1/2012	12/1/2012	4.738	[redacted]
42	7/7/2011	[redacted]	1/1/2013	12/1/2013	5.064	[redacted]
43	7/28/2011	[redacted]	1/1/2013	12/1/2013	5.102	[redacted]
44	7/29/2011	[redacted]	1/1/2013	12/1/2013	5.047	[redacted]
45	7/29/2011	[redacted]	1/1/2012	12/1/2012	4.641	[redacted]
46	8/3/2011	[redacted]	1/1/2012	12/1/2012	4.614	[redacted]
47	8/3/2011	[redacted]	1/1/2013	12/1/2013	5.053	[redacted]
48	8/4/2011	[redacted]	1/1/2013	12/1/2013	4.959	[redacted]
49	8/29/2011	[redacted]	1/1/2013	12/1/2013	4.901	[redacted]
50	9/9/2011	[redacted]	1/1/2013	12/1/2013	4.930	[redacted]
51	9/15/2011	[redacted]	1/1/2013	12/1/2013	4.927	[redacted]

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
52	9/29/2011	[redacted]	1/1/2013	12/1/2013	4.821	[redacted]
53	10/3/2011	[redacted]	1/1/2013	12/1/2013	4.785	[redacted]
54	10/7/2011	[redacted]	1/1/2013	12/1/2013	4.682	[redacted]
55	10/18/2011	[redacted]	1/1/2013	12/1/2013	4.615	[redacted]
56	11/4/2011	[redacted]	1/1/2012	12/1/2012	4.010	[redacted]
57	11/7/2011	[redacted]	1/1/2013	12/1/2013	4.507	[redacted]
58	11/7/2011	[redacted]	1/1/2012	12/1/2012	3.917	[redacted]
59	11/8/2011	[redacted]	1/1/2012	12/1/2012	3.956	[redacted]
60	11/9/2011	[redacted]	1/1/2012	12/1/2012	3.865	[redacted]
61	11/9/2011	[redacted]	1/1/2013	12/1/2013	4.452	[redacted]
62	11/11/2011	[redacted]	1/1/2012	12/1/2012	3.827	[redacted]
63	11/11/2011	[redacted]	1/1/2013	12/1/2013	4.394	[redacted]
64	11/14/2011	[redacted]	1/1/2012	12/1/2012	3.758	[redacted]
65	11/14/2011	[redacted]	1/1/2013	12/1/2013	4.361	[redacted]
66	11/15/2011	[redacted]	1/1/2012	12/1/2012	3.703	[redacted]
67	11/16/2011	[redacted]	1/1/2012	12/1/2012	3.633	[redacted]
68	11/18/2011	[redacted]	5/1/2013	12/1/2013	4.316	[redacted]
69	11/22/2011	[redacted]	1/1/2012	12/1/2012	3.741	[redacted]
70	11/22/2011	[redacted]	5/1/2013	12/1/2013	4.351	[redacted]
71	11/23/2011	[redacted]	5/1/2013	12/1/2013	4.373	[redacted]
72	11/23/2011	[redacted]	1/1/2012	12/1/2012	3.789	[redacted]
73	11/28/2011	[redacted]	1/1/2012	12/1/2012	3.746	[redacted]
74	11/30/2011	[redacted]	1/1/2012	12/1/2012	3.733	[redacted]
75	12/5/2011	[redacted]	1/1/2013	12/1/2013	4.363	[redacted]
76	12/9/2011	[redacted]	1/1/2013	12/1/2013	4.162	[redacted]
77	12/14/2011	[redacted]	5/1/2013	12/1/2013	4.061	[redacted]
78	12/28/2011	[redacted]	1/1/2013	12/1/2013	4.035	[redacted]
79	1/5/2012	[redacted]	5/1/2013	12/1/2013	3.960	[redacted]
80	1/11/2012	[redacted]	6/1/2013	8/1/2013	3.747	[redacted]
81	1/17/2012	[redacted]	5/1/2013	12/1/2013	3.582	[redacted]
82	1/19/2012	[redacted]	1/1/2013	12/1/2013	3.398	[redacted]

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
83	1/26/2012	[redacted]	5/1/2012	12/1/2012	3.030	[redacted]
84	1/26/2012	[redacted]	1/1/2013	12/1/2013	3.656	[redacted]
85	1/30/2012	[redacted]	1/1/2013	12/1/2013	3.678	[redacted]
86	1/30/2012	[redacted]	5/1/2012	12/1/2012	3.060	[redacted]
87	1/31/2012	[redacted]	5/1/2012	12/1/2012	2.889	[redacted]
88	1/31/2012	[redacted]	1/1/2013	12/1/2013	3.571	[redacted]
89	2/9/2012	[redacted]	1/1/2013	12/1/2013	3.693	[redacted]
90	2/27/2012	[redacted]	5/1/2012	12/1/2012	2.902	[redacted]
91	2/27/2012	[redacted]	1/1/2013	12/1/2013	3.681	[redacted]
92	2/28/2012	[redacted]	1/1/2013	12/1/2013	3.601	[redacted]
93	3/5/2012	[redacted]	6/1/2013	12/1/2013	3.567	[redacted]
94	3/7/2012	[redacted]	1/1/2013	12/1/2013	3.411	[redacted]
95	3/13/2012	[redacted]	1/1/2013	12/1/2013	3.525	[redacted]
96	3/29/2012	[redacted]	1/1/2013	12/1/2013	3.428	[redacted]
97	4/11/2012	[redacted]	1/1/2013	12/1/2013	3.393	[redacted]
98	4/17/2012	[redacted]	1/1/2013	12/1/2013	3.343	[redacted]
99	4/19/2012	[redacted]	1/1/2013	12/1/2013	3.272	[redacted]
100	5/10/2012	[redacted]	6/1/2013	12/1/2013	3.721	[redacted]
101	5/21/2012	[redacted]	6/1/2013	9/1/2013	3.557	[redacted]
102	5/23/2012	[redacted]	6/1/2013	12/1/2013	3.669	[redacted]
103	5/25/2012	[redacted]	6/1/2013	9/1/2013	3.504	[redacted]
104	5/30/2012	[redacted]	1/1/2013	3/1/2013	3.258	[redacted]
105	5/30/2012	[redacted]	5/1/2013	12/1/2013	3.436	[redacted]
106	6/7/2012	[redacted]	1/1/2013	12/1/2013	3.402	[redacted]
107	6/13/2012	[redacted]	1/1/2013	12/1/2013	3.329	[redacted]
108	6/28/2012	[redacted]	1/1/2013	12/1/2013	3.566	[redacted]
109	7/6/2012	[redacted]	1/1/2013	12/1/2013	3.570	[redacted]
110	7/10/2012	[redacted]	11/1/2012	3/1/2013	3.345	[redacted]
111	7/12/2012	[redacted]	6/1/2013	12/1/2013	3.690	[redacted]
112	7/25/2012	[redacted]	11/1/2012	3/1/2013	3.501	[redacted]
113	8/1/2012	[redacted]	11/1/2012	3/1/2013	3.568	[redacted]

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
114	8/1/2012	[redacted]	6/1/2013	12/1/2013	3.781	[redacted]
115	8/2/2012	[redacted]	11/1/2012	3/1/2013	3.361	[redacted]
116	8/2/2012	[redacted]	6/1/2013	12/1/2013	3.605	[redacted]
117	8/3/2012	[redacted]	11/1/2012	3/1/2013	3.324	[redacted]
118	8/10/2012	[redacted]	11/1/2012	3/1/2013	3.354	[redacted]
119	8/10/2012	[redacted]	5/1/2013	12/1/2013	3.628	[redacted]
120	8/13/2012	[redacted]	5/1/2013	12/1/2013	3.586	[redacted]
121	8/13/2012	[redacted]	11/1/2012	3/1/2013	3.327	[redacted]
122	8/16/2012	[redacted]	11/1/2012	3/1/2013	3.302	[redacted]
123	8/16/2012	[redacted]	5/1/2013	12/1/2013	3.548	[redacted]
124	8/23/2012	[redacted]	11/1/2012	3/1/2013	3.357	[redacted]
125	8/23/2012	[redacted]	6/1/2013	12/1/2013	3.619	[redacted]
126	8/24/2012	[redacted]	11/1/2012	3/1/2013	3.283	[redacted]
127	8/27/2012	[redacted]	6/1/2013	12/1/2013	3.500	[redacted]
128	9/5/2012	[redacted]	1/1/2013	12/1/2013	3.461	[redacted]
129	9/7/2012	[redacted]	11/1/2012	12/1/2012	2.988	[redacted]
130	9/7/2012	[redacted]	1/1/2013	12/1/2013	3.376	[redacted]
131	9/17/2012	[redacted]	11/1/2012	12/1/2012	3.178	[redacted]
132	9/18/2012	[redacted]	1/1/2013	12/1/2013	3.512	[redacted]
133	9/18/2012	[redacted]	11/1/2012	12/1/2012	3.139	[redacted]
134	10/22/2012	[redacted]	11/1/2012	2/1/2013	3.759	[redacted]
135	10/24/2012	[redacted]	11/1/2012	2/1/2013	3.719	[redacted]
136	10/25/2012	[redacted]	11/1/2012	2/1/2013	3.648	[redacted]
137	10/26/2012	[redacted]	11/1/2012	2/1/2013	3.712	[redacted]
138	11/1/2012	[redacted]	12/1/2012	2/1/2013	3.773	[redacted]
139	11/2/2012	[redacted]	4/1/2013	10/1/2013	3.745	[redacted]
140	11/2/2012	[redacted]	12/1/2012	2/1/2013	3.647	[redacted]
141	11/9/2012	[redacted]	4/1/2013	10/1/2013	3.713	[redacted]
142	11/9/2012	[redacted]	12/1/2012	2/1/2013	3.595	[redacted]
143	11/26/2012	[redacted]	12/1/2012	2/1/2013	3.779	[redacted]
144	11/28/2012	[redacted]	12/1/2012	12/1/2012	3.696	[redacted]

	(A)	(B)	(C)	(D)	(E)	(F)
	Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBTU)	% Difference
145	11/29/2012	[redacted]	1/1/2013	2/1/2013	3.658	[redacted]
146	11/30/2012	[redacted]	4/1/2013	10/1/2013	3.672	[redacted]
147	11/30/2012	[redacted]	1/1/2013	2/1/2013	3.573	[redacted]
148	12/4/2012	[redacted]	1/1/2013	2/1/2013	3.551	[redacted]
149	12/4/2012	[redacted]	7/1/2013	9/1/2013	3.697	[redacted]
150	12/11/2012	[redacted]	6/1/2013	12/1/2013	3.647	[redacted]
151	1/2/2013	[redacted]	6/1/2013	12/1/2013	3.564	[redacted]
152	1/9/2013	[redacted]	6/1/2013	12/1/2013	3.467	[redacted]
153	1/29/2013	[redacted]	2/1/2013	2/1/2013	3.258	[redacted]
154	5/16/2013	[redacted]	6/1/2013	10/1/2013	3.988	[redacted]
155	5/22/2013	[redacted]	6/1/2013	9/1/2013	4.227	[redacted]
156	5/31/2013	[redacted]	6/1/2013	6/1/2013	3.984	[redacted]
157	5/31/2013	[redacted]	7/1/2013	7/1/2013	3.984	[redacted]
158	6/6/2013	[redacted]	7/1/2013	12/1/2013	3.898	[redacted]
159	6/6/2013	[redacted]	6/1/2013	6/1/2013	3.827	[redacted]
160	6/6/2013	[redacted]	7/1/2013	7/1/2013	3.827	[redacted]
161	6/21/2013	[redacted]	7/1/2013	7/1/2013	3.771	[redacted]
162	6/24/2013	[redacted]	8/1/2013	12/1/2013	3.830	[redacted]

49. For interrogatory 48 above, please explain any difference between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

ANSWER:

There are no swap deals with a difference between the fixed price and the forward price that is greater than 5 percent.

50. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with options for natural gas prices, please provide the following information:
(a) the transaction date for the option;
(b) the option price or premium;
(c) the type of option;
(d) the time to expiration; and
(e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

ANSWER:

	(A) Date Deal Was Entered	(B) Strike Price $/MMBTU	(C) Option Premium	(D) Portfolio	(E) Put Call	(F) Direction	(G) Period Covered	(H) Average NYMEX Price at Market Close ($/MMBTU)
1	9/21/2011	[redacted]	$0.09	Collar	Call	Buy	Jan-Dec, 2012	4.374
2	9/21/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	4.374
3	9/29/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	4.277
4	9/29/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	4.277
5	10/3/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	4.206
6	10/3/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	4.206
7	10/18/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	4.087
8	10/18/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	4.087
9	11/1/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	4.057
10	11/1/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	4.057
11	12/5/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	3.757
12	12/5/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	3.757
13	12/7/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	3.724
14	12/7/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	3.724
15	12/9/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	3.610
16	12/9/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	3.610
17	12/22/2011	[redacted]	$0.00	Collar	Call	Buy	Jan-Dec, 2012	3.510
18	12/22/2011	[redacted]	$0.00	Collar	Put	Sell	Jan-Dec, 2012	3.510

51. For interrogatory 50 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

ANSWER:

In all of the collar transactions, the future price is within the bounds of the collar strike price.

52. Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2012, and ending July 31, 2013.

ANSWER:

Hedge Month	Fuel Type	Swaps	Options*	Total
Aug-12	Natural Gas	$2,718,558	$167,860	$2,886,418
Sep-12	Natural Gas	$2,749,988	$172,650	$2,922,638
Oct-12	Natural Gas	$1,787,676	$103,740	$1,891,416
Nov-12	Natural Gas	$1,218,355	$ 49,980	$1,268,335
Dec-12	Natural Gas	$1,919,424	$ 45,780	$1,965,204
Jan-13	Natural Gas	$2,013,400		$2,013,400
Feb-13	Natural Gas	$2,166,655		$2,166,655
Mar-13	Natural Gas	$ 793,231		$ 793,231
Apr-13	Natural Gas	$ 403,524		$ 403,524
May-13	Natural Gas	$ 493,084		$ 493,084
Jun-13	Natural Gas	$ 917,710		$ 917,710
Jul-13	Natural Gas	$1,693,990		$1,693,990

*All options transacted were collars.

53. For the twelve months beginning August 1, 2012, and ending July 31, 2013, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in Gulf's risk management plan or otherwise stated in internal procedures governing Gulf's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

ANSWER:

Gulf does not establish monthly targets but rather has a target range for hedge volumes as a percentage of its annual gas burn for its gas fired generation units. Actual gas burn for the period was 66,963,082 MMBTU and the hedged amount for the period was 32,340,000 MMBTU. The hedged amount is equivalent to 48 percent of the actual burn for the period. This is within the target hedge range established in Gulf's Risk Management Plan.

54. Please provide a comparison of Gulf's Risk Management Plans for 2013 and 2014. Please describe any changes between these respective plans.

ANSWER:

The table below provides a comparison of the upper target hedge percentages from Gulf's Risk Management Plans for 2013 and 2014. The upper target hedge percentages have been increased in the 2014 Risk Management Plan because of Gulf's increase reliance on natural gas and low forward prices. There were no other changes made to Gulf's Risk Management Plan between 2013 and 2014.

	A	B	C
	Period	2013 Risk Management Plan	2014 Risk Management Plan
1	Prompt Year	[redacted]	[redacted]
2	Year 2		
3	Year 3		
4	Year 4		
5	Year 5		

55. Regarding hedging activities, how does Gulf assess and evaluate counter-party credit risk?

ANSWER:

Gulf only enters into material agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor'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. In addition, 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.

56. For open hedging transactions since August 1, 2012, has Gulf experienced any defaults by a counter-party? If so, please identify the counter-party and explain.

ANSWER:

No.

57. For all currently open hedging transactions, does Gulf have any concern regarding default by a counter-party for any specific transaction? If so, please identify the counter-party and explain.

ANSWER:

No.

58. Since January 1, 2012, has Gulf stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If so, please identify the counter-party and explain.

ANSWER:

No.

59. Has Gulf incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If so, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

ANSWER:

No.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 130001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 15th day of October, 2013.

Melissa A. Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA

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

83

TECO's Responses to Staff's First Set of Interrogatories (Nos. 1-12)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 83
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0539-0577]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: March 4, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-12)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 1-12) propounded and served on January 31, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 1-12)

Number	Witness	Subject	Bates Stamped Page
1	Rusk	In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 through 2: Please quantify and discuss all the costs and benefits under the following three scenarios. If the billing system does not have the ability to implement a particular scenario, explain why. (a) The January first billing cycle is set for January 1 or later each year (i.e., first billing cycle for January would not begin in December of prior year); (b) The effective date of new factors would be with the first billing cycle in February each year; (c) The effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (i.e., any December or November usage would be billed under prior factors).	1
2	Rusk	Please discuss when and how customers receive notice of the new January factors.	3
3	Buckley	Interrogatory Nos. 3-2 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel. For each type of fuel used for the power generated by the GPIF units dispatched, provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.	4

4	Buckley	For each type of fuel used for the power generated by all units dispatched (including non-GPIF units), provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.	8
5	Buckley	Please provide the calculations of the maximum potential GPIF incentive amount allowed per 1,000 kWh jurisdictional sales for each year since the implementation of the GPIF. As part of the response, please show the maximum allowed jurisdictional GPIF incentive dollars, jurisdictional sales, and the percentage for heat rate incentive and availability incentive respectively.	17
6	Buckley / Rusk	Please describe the various factors that could impact the efficient use of capital and over the long term, rates paid by customers. As part of the response, please provide the fuel and base rates breakdown for 1,000 kWh residential usage, the authorized ROE used to set base rates, the net energy for load, net MWh purchased power, net MWh generation, and T&D loss, for 1980, 1990, 2000, 2010, 2011, and 2012.	19
7	Buckley	Please provide the projected GPIF heat rate target (Btus per kWh) and the projected MWh net generation of each GPIF unit for the years 2000 through 2012.	20
8	Buckley	Please provide the actual heat rate performance (Btus per kWh) and the actual MWh net generation of each GPIF unit for the years 2000 through 2012.	22
9	Buckley	Please provide the projected GPIF Equivalent Availability Factor (EAF) target and the MW capacity of each GPIF unit for the years 2000 through 2012.	24
10	Buckley	Please provide the actual GPIF Equivalent Availability Factor (EAF) performance and the MW capacity for each GPIF unit for the years 2000 through 2012.	25
11	Buckley	Please describe the improvement or decline in your company's heat rate performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the	26

		response, please provide the data and calculations supporting the following: (a) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89; (b) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1990-99; (c) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2000-09; (d) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2010-12; (e) The amount of capital and O&M required and deployed for the heat rate improvement in each period; (f) The amount of net GPIF incentive payments for the heat rate performance in each period (annual and cumulative); (g) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1980-89; (h) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1990-99; (i) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2000-09; (j) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2010-12; (k) The alternative analysis (if any).	

12	Buckley	Please describe the improvement or decline in your company's availability performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following: (a) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89; (b) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1990-99; (c) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2000-09; (d) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2010-12; (e) The amount of capital and O&M required and deployed for the improvement in each period; (f) The amount of net GPIF incentive payments for the availability factor performance in each period (annual and cumulative); (g) The annual average rate of change in the composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1980-89; (h) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1990-99; (i) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2000-09;	29

		(j) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2010-12; (k) The alternative analysis (if any).	

Brian Buckley
Manager, Compliance and Performance

Penelope Rusk
Administrator, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

In Order No. PSC-12-0664-FOF-EI the Commission authorized staff to investigate a change in the annual fuel cost recovery clause effective date of the new factors to begin on or after the first billing cycle in January. With respect to that investigation, please respond to interrogatory numbers 1 through 2:

1. Please quantify and discuss all the costs and benefits under the following three scenarios. If the billing system does not have the ability to implement a particular scenario, explain why.

   (a) The January first billing cycle is set for January 1 or later each year (i.e., first billing cycle for January would not begin in December of prior year);

   (b) The effective date of new factors would be with the first billing cycle in February each year;

   (c) The effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (i.e., any December or November usage would be billed under prior factors).

A. (a) There are no additional costs or benefits for Tampa Electric associated with having the first billing cycle set for January 1 or later each year.

   (b) There are no additional costs or benefits for Tampa Electric associated with adopting the first billing cycle in February each year as the effective date for new fuel cost recovery clause factors as long as the same effective date is adopted for all of the other cost recovery clause factors (*e.g.*, ECRC, ECCR).

   (c) With its current billing and metering systems, Tampa Electric does not have the ability to implement the scenario under which the effective date remains with the first billing cycle in January; however, new factors could only be applied to usage on or after the first billing cycle in January (*i.e.*, any December or November usage would be billed under prior factors).

   Additionally, the vast majority of the company's installed meters are not capable of providing consumption information by time or date. Currently, only the company's costly interval data meters can provide consumption in

130001 Hearing Exhibits - 00546

this manner, and the metering data from these meters must be manually translated before being passed to the billing system.

The current billing system would require extensive programming changes involving a master file expansion in order to accept, store, and bill multiple consumption readings at multiple factors within one bill. Reporting and displaying the information would also add to the significant costs of modification.

2. Please discuss when and how customers receive notice of the new January factors.

A. A customer bill insert is distributed to customers beginning with the first billing cycle in December, notifying them of the changes to occur beginning January. E-Bill customers are provided a link to the inserts which are posted on Tampa Electric's website.

Interrogatory Nos. 3-2 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

3. For each type of fuel used for the power generated by the GPIF units dispatched, provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

A. The requested information is provided in the tables below and in a spreadsheet file. Tampa Electric retrieved this data from Schedule A-5 for 1980 and 1990 data and from Schedule A-4 for 2000 and forward.

1980 (April thru December only)
GPIF Units Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	896,425			
Big Bend 2 Coal	1,808,021			
Big Bend 3 Coal	1,970,320			
Big Bend Total	**4,674,766**	**47,058,621.0**	**10,067**	**$82,433,917**
Gannon 5 Coal	891,912			
Gannon 6 Coal	1,535,520			
Gannon 5-6 Total	**2,427,432**	**24,590,988.0**	**10,130**	**$53,940,629**
Total GPIF Units	**7,102,198**	**71,649,609.0**	**10,088**	**$136,374,546**

Source: Schedule A5 in Monthly Fuel Filing
Note: No available records prior to April 1980

1990
GPIF Units Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	1,662,469			
Big Bend 2 Coal	2,411,798			
Big Bend 3 Coal	2,841,576			
Big Bend 4 Coal	3,098,179			
Big Bend Total	10,014,022	98,205,730.3	9,807	$184,152,725
Gannon 5 Coal	1,473,934			
Gannon 6 Coal	911,791			
Gannon 5-6 Total	2,385,725	24,196,744.8	10,142	$58,378,286
Total GPIF Units	12,399,747	122,402,475.1	9,871	$242,531,011

Source: Schedule A5 in True-Up Filing

2000
GPIF Units Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	2,422,094	25,089,273.6	10,359	$43,626,892
Big Bend 2 Coal	2,721,653	27,317,102.2	10,037	47,585,532
Big Bend 3 Coal	2,479,260	24,462,799.0	9,867	43,111,925
Big Bend 4 Coal	3,090,091	30,579,349.3	9,896	71,043,085
Big Bend Total Coal	10,713,098	107,448,524.1	10,030	$205,367,434
Gannon 5 Coal	931,061	10,007,269.3	10,748	$16,791,798
Gannon 6 Coal	899,588	9,446,812.7	10,501	14,882,173
Gannon Total Coal	1,830,649	19,454,082.0	10,627	$31,673,971
Polk 1 Total	1,691,036	17,549,677.0	10,378	$34,472,361
Total GPIF Units	14,234,783	144,452,283.1	10,148	$271,513,766

Source: Schedule A4 in True-Up Filing

2010
GPIF Units Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	1,978,198	19,805,772.4	10,012	$59,796,260
Big Bend 2 Coal	2,197,116	21,932,285.2	9,982	65,229,892
Big Bend 3 Coal	2,434,151	25,648,824.1	10,537	78,389,392
Big Bend 4 Coal	2,376,875	24,125,637.0	10,150	74,297,254
Big Bend Ignition Lt Oil	-	277,036.4	-	5,225,310
Big Bend Total Coal	**8,986,340**	**91,512,518.7**	**10,184**	**$282,938,108**
Polk 1 Total	**1,664,556**	**16,726,899.8**	**10,049**	**$56,391,838**
Bayside Unit 1 Total	**3,403,936**	**24,713,917.0**	**7,260**	**$167,076,534**
Bayside Unit 2 Total	**4,599,663**	**33,925,039.0**	**7,376**	**$227,544,304**
Total GPIF Units	**18,654,495**	**166,878,374.5**	**8,946**	**$733,950,784**

Source: Schedule A4 in Monthly Fuel Filing

2011
GPIF Units Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	2,591,164	28,158,172.2	10,867	$88,654,420
Big Bend 2 Coal	1,879,739	19,750,818.4	10,507	60,894,121
Big Bend 3 Coal	2,305,767	23,853,039.5	10,345	76,061,749
Big Bend 4 Coal	2,641,388	27,659,658.6	10,472	91,089,925
Big Bend Ignition Lt Oil	-	243,491.8	-	4,847,488
Big Bend Total Coal	**9,418,058**	**99,421,688.7**	**10,556**	**$321,547,703**
Polk 1 Total	**1,483,473**	**15,115,005.3**	**10,189**	**$67,788,290**
Bayside Unit 1 Total	**2,501,377**	**18,114,990.5**	**7,242**	**$110,329,663**
Bayside Unit 2 Total	**4,359,331**	**32,124,977.0**	**7,369**	**$201,884,663**
Total GPIF Units	**17,762,239**	**164,776,661.5**	**9,277**	**$701,550,319**

Source: Schedule A4 in Monthly Fuel Filing

2012 GPIF Units Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	2,154,188	22,572,810.6	10,479	$76,562,152
Big Bend 2 Coal	2,519,165	26,177,193.8	10,391	89,005,426
Big Bend 3 Coal	2,220,002	23,613,453.0	10,637	80,793,093
Big Bend 4 Coal	2,622,227	27,367,274.7	10,437	95,413,313
Big Bend Ignition Lt Oil	-	361,730.2	-	7,783,923
Big Bend Total Coal	**9,515,582**	**99,730,732.1**	**10,481**	**$349,557,907**
Polk 1 Total	**1,194,915**	**12,780,481.3**	**10,696**	**$50,387,523**
Bayside Unit 1 Total	**3,110,796**	**22,467,785.0**	**7,223**	**$118,839,338**
Bayside Unit 2 Total	**3,930,991**	**28,910,720.0**	**7,355**	**$155,971,618**
Total GPIF Units	**17,752,284**	**163,889,718.4**	**9,232**	**$674,756,386**

Source: Schedule A4 in Monthly Fuel Filing

130001 Hearing Exhibits - 00552

4. For each type of fuel used for the power generated by all units dispatched (including non-GPIF units), provide the energy input (MMBtu), power output (MWh), annual average heat rate (MMBtu/MWh), and fuel cost (Dollar) for 1980, 1990, 2000, 2010, 2011, and 2012. Please specify data source such as Schedule A-3 filed in the fuel docket.

A. The requested information is provided in the tables below and in a spreadsheet file.

1980 (April thru December only)
Total System Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Hookers Point 1 Hvy Oil	50,898			
Hookers Point 2 Hvy Oil	25,256			
Hookers Point 3 Hvy Oil	12,436			
Hookers Point 4 Hvy Oil	55,993			
Hookers Point 5 Hvy Oil	175,009			
Hooker Point Total	**319,592**	**4,340,381.0**	**13,581**	**$16,060,154**
Gannon 1 Hvy Oil	272,475			
Gannon 2 Hvy Oil	302,762			
Gannon 3 Hvy Oil	339,089			
Gannon 4 Hvy Oil	637,000			
Gannon 1-4 Total	**1,551,326**	**17,232,255.0**	**11,108**	**$64,296,457**
Gannon 5 Coal	891,912			
Gannon 6 Coal	1,535,520			
Gannon 5-6 Total	**2,427,432**	**24,590,988.0**	**10,130**	**$53,940,629**
Big Bend 1 Coal	896,425			
Big Bend 2 Coal	1,808,021			
Big Bend 3 Coal	1,970,320			
Big Bend Total	**4,674,766**	**47,058,621.0**	**10,067**	**$82,433,917**
Gannon CT 1 Lt Oil	1,820			
Big Bend CT 1 Lt Oil	1,852			
Big Bend CT 2 Lt Oil	23,920			
Big Bend CT 3 Lt Oil	20,069			
Total CT's	**47,661**	**703,861.0**	**14,768**	**$4,069,393**
System Total	**9,020,777**	**93,926,106.0**	**10,412**	**$220,800,550**

Source: Schedule A5 in Monthly Fuel Filing
Note: No available records prior to April 1980

1990
Total System Net Generation, MMbtu, Heat Rate and Fuel Cost

Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Hookers Point 1 Hvy Oil	0			
Hookers Point 2 Hvy Oil	1,450			
Hookers Point 3 Hvy Oil	5,181			
Hookers Point 4 Hvy Oil	7,732			
Hookers Point 5 Hvy Oil	460			
Hooker Point Total	**14,823**	**240,150.3**	**16,201**	**$1,130,833**
Gannon 1 Hvy Oil	592,475			
Gannon 2 Hvy Oil	603,861			
Gannon 3 Hvy Oil	785,083			
Gannon 4 Hvy Oil	929,105			
Gannon 1-4 Total	**2,910,524**	**31,871,706.2**	**10,951**	**$76,725,531**
Gannon 5 Coal	1,473,934			
Gannon 6 Coal	911,791			
Gannon 5-6 Total	**2,385,725**	**24,196,744.8**	**10,142**	**$58,378,286**
Big Bend 1 Coal	1,662,469			
Big Bend 2 Coal	2,411,798			
Big Bend 3 Coal	2,841,576			
Big Bend 4 Coal	3,098,179			
Big Bend Total	**10,014,022**	**98,205,730.3**	**9,807**	**$184,152,725**
Gannon CT 1 Lt Oil	2,691			
Big Bend CT 1 Lt Oil	2,572			
Big Bend CT 2 Lt Oil	34,123			
Big Bend CT 3 Lt Oil	30,173			
Total CT's	**69,559**	**1,086,896.7**	**15,626**	**$5,678,550**
System Total	**15,394,653**	**155,601,228.3**	**10,107**	**$326,065,925**

Source: Schedule A5 in True-Up Filing

2000 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Hookers Point 1 Hvy Oil	23,049			
Hookers Point 2 Hvy Oil	27,380			
Hookers Point 3 Hvy Oil	24,965			
Hookers Point 4 Hvy Oil	28,285			
Hookers Point 5 Hvy Oil	42,317			
Hooker Point Total	**145,996**	**2,462,000.2**	**16,863**	**$9,743,274**
Gannon 1 Coal	544,513	6,306,314.1	11,582	$10,607,262
Gannon 2 Coal	446,713	5,462,982.5	12,229	9,335,062
Gannon 3 Coal	773,472	9,356,579.6	12,097	19,011,812
Gannon 4 Coal	759,811	9,074,945.6	11,944	18,392,967
Gannon 5 Coal	931,061	10,007,269.3	10,748	16,791,798
Gannon 6 Coal	899,588	9,446,812.7	10,501	14,882,173
Gannon Total Coal	**4,355,158**	**49,654,903.8**	**11,401**	**$89,021,074**
Big Bend 1 Coal	2,422,094	25,089,273.6	10,359	$43,626,892
Big Bend 2 Coal	2,721,653	27,317,102.2	10,037	47,585,532
Big Bend 3 Coal	2,479,260	24,462,799.0	9,867	43,111,925
Big Bend 4 Coal	3,090,091	30,579,349.3	9,896	71,043,085
Big Bend Total Coal	**10,713,098**	**107,448,524.1**	**10,030**	**$205,367,434**
Sebring Phillips 1 Hvy Oil	37,204	368,108.2	9,894	$1,719,389
Sebring Phillips 2 Hvy Oil	41,719	366,734.2	8,791	1,715,120
Sebring Phillips Total	**78,923**	**734,842.4**	**9,311**	**$3,434,509**
Polk 1 Coal	1,611,021	16,883,111.0	10,480	$29,940,448
Polk 1 CT Lt Oil	80,015	666,566.0	8,331	4,531,913
Polk 1 Total	**1,691,036**	**17,549,677.0**	**10,378**	**$34,472,361**
Polk 2 Gas	135,455	1,552,203.0	11,459	$8,529,409
Polk 2 CT Lt Oil	70,619	825,859.9	11,695	5,370,674
Polk 2 Total	**206,074**	**2,378,062.9**	**11,540**	**$13,900,083**
Gannon CT 1 Lt Oil	**3,507**	**30,415.1**	**8,673**	**$178,636**
Big Bend CT 1 Lt Oil	4,871	91,577.8	18,801	$567,704
Big Bend CT 2 Lt Oil	41,064	643,156.0	15,662	4,029,229
Big Bend CT 3 Lt Oil	43,315	641,906.3	14,819	4,053,439
Big Bend CT Total	**89,250**	**1,376,640.1**	**15,425**	**$8,650,372**
System Total	17,283,042	181,635,065.6	10,509	$364,767,743

Source: Schedule A4 in True-Up Filing

2010 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	1,978,198	19,805,772.4	10,012	$59,796,260
Big Bend 2 Coal	2,197,116	21,932,285.2	9,982	65,229,892
Big Bend 3 Coal	2,434,151	25,648,824.1	10,537	78,389,392
Big Bend 4 Coal	2,376,875	24,125,637.0	10,150	74,297,254
Big Bend Ignition Lt Oil	-	277,036.4	-	5,225,310
Big Bend Total Coal	**8,986,340**	**91,512,518.7**	**10,184**	**$282,938,108**
Big Bend CT 4 Gas	42,268	471,183.3	11,148	$3,127,125
Big Bend CT 4 Lt Oil	4,293	40,937.5	9,536	616,953
Big Bend CT 4 Total	**46,561**	**512,120.8**	**10,999**	**$3,744,078**
Big Bend Station Total	**9,032,901**	**92,024,639.5**	**10,188**	**$286,682,186**
Sebring Phillips Ignition				**$28,030**
Polk 1 Coal	1,626,594	16,379,026.6	10,070	$50,698,189
Polk 1 CT Lt Oil	37,962	347,873.2	9,164	5,693,649
Polk 1 Total	**1,664,556**	**16,726,899.8**	**10,049**	**$56,391,838**
Polk 2 Gas	22,217	256,384.0	11,540	$1,785,927
Polk 2 CT Lt Oil	3,883	51,923.2	13,372	764,206
Polk 2 Total	**26,100**	**308,307.2**	**11,813**	**$2,550,133**
Polk 3 Gas	18,035	251,239.0	13,931	$1,672,829
Polk 3 CT Lt Oil	3,339	47,999.0	14,375	765,652
Polk 3 Total	**21,374**	**299,238.0**	**14,000**	**$2,438,481**
Polk 4 Gas	**58,924**	**721,576.0**	**12,246**	**$4,767,728**
Polk 5 Gas	**50,131**	**607,257.0**	**12,113**	**$4,141,668**
Polk Station Total	**1,821,085**	**18,663,278.0**	**10,248**	**$70,289,848**
City of Tampa 1	(6)	640.0	(114,110)	$7,627
City of Tampa 2	(53)	785.5	(14,712)	9,890
City of Tampa Total	**(59)**	**1,425.5**	**(24,161)**	**$17,517**
Bayside ST 1	1,175,158	-	-	-
Bayside CT1A	659,008	7,445,142.0	11,297	$50,718,948
Bayside CT1B	737,031	8,313,154.0	11,279	56,127,290
Bayside CT1C	832,739	8,955,621.0	10,754	60,230,296
Bayside Unit 1 Total	**3,403,936**	**24,713,917.0**	**7,260**	**$167,076,534**
Bayside ST 2	1,593,051	-	-	-
Bayside CT2A	749,806	8,381,193.0	11,178	$56,437,624

2010 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Bayside CT2B	730,247	8,261,905.0	11,314	55,511,469
Bayside CT2C	767,859	8,675,539.0	11,298	58,127,041
Bayside CT2D	758,700	8,606,402.0	11,344	57,468,170
Bayside Unit 2 Total	4,599,663	33,925,039.0	7,376	$227,544,304
Bayside Unit 3 Total	52,274	601,251.0	11,502	$4,102,917
Bayside Unit 4 Total	49,870	568,810.0	11,406	$3,851,993
Bayside Unit 5 Total	40,129	470,000.0	11,712	$3,151,850
Bayside Unit 6 Total	37,357	427,257.0	11,437	$2,901,646
Bayside Station Total	8,183,229	60,706,274.0	7,418	$408,629,244
System Total	19,037,156	171,395,617.0	9,003	$765,646,825

Source: Schedule A4 in Monthly Fuel Filing

2011 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	2,591,164	28,158,172.2	10,867	$88,654,420
Big Bend 2 Coal	1,879,739	19,750,818.4	10,507	60,894,121
Big Bend 3 Coal	2,305,767	23,853,039.5	10,345	76,061,749
Big Bend 4 Coal	2,641,388	27,659,658.6	10,472	91,089,925
Big Bend Ignition Lt Oil	-	243,491.8	-	4,847,488
Big Bend Total Coal	**9,418,058**	**99,421,688.7**	**10,556**	**$321,547,703**
Big Bend CT 4 Gas	7,608	108,727.4	14,291	$690,727
Big Bend CT 4 Lt Oil	74	535.9	7,242	9,954
Big Bend CT 4 Total	**7,682**	**109,263.3**	**14,223**	**$700,681**
Big Bend Station Total	**9,425,740**	**99,530,952.0**	**10,559**	**$322,248,384**
Polk 1 Coal	1,470,124	14,969,522.6	10,182	$64,882,658
Polk 1 CT Lt Oil	13,349	145,482.7	10,898	2,905,632
Polk 1 Total	**1,483,473**	**15,115,005.3**	**10,189**	**$67,788,290**
Polk 2 Gas	55,249	643,263.0	11,643	$3,836,604
Polk 2 CT Lt Oil	0	0.0	0	-
Polk 2 Total	**55,249**	**643,263.0**	**11,643**	**$3,836,604**
Polk 3 Gas	107,794	1,280,436.0	11,879	$7,615,186
Polk 3 CT Lt Oil	0	0.0	0	0
Polk 3 Total	**107,794**	**1,280,436.0**	**11,879**	**$7,615,186**
Polk 4 Gas	**151,001**	**1,758,376.0**	**11,645**	**$10,612,114**
Polk 5 Gas	**154,327**	**1,618,694.0**	**10,489**	**$9,381,123**
Polk Station Total	**1,951,844**	**20,415,774.3**	**10,460**	**$99,233,317**
City of Tampa 1	(107)	0.0	0	$1,764
City of Tampa 2	-	0.0	0	1,764
City of Tampa Total	**(107)**	**0.0**	**0**	**$3,528**
Bayside ST 1	861,789	-	-	-
Bayside CT1A	560,526	6,334,684.7	11,301	$40,460,834
Bayside CT1B	556,258	6,228,942.5	11,198	36,872,204
Bayside CT1C	522,804	5,551,363.3	10,618	32,996,625
Bayside Unit 1 Total	**2,501,377**	**18,114,990.5**	**7,242**	**$110,329,663**
Bayside ST 2	1,502,188	-	-	-

130001 Hearing Exhibits - 00558

2011 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Bayside CT2A	718,321	8,013,648.0	11,156	$50,728,074
Bayside CT2B	723,170	8,159,993.0	11,284	51,556,452
Bayside CT2C	727,188	8,199,211.0	11,275	51,413,545
Bayside CT2D	688,464	7,752,125.0	11,260	48,186,592
Bayside Unit 2 Total	**4,359,331**	**32,124,977.0**	**7,369**	**$201,884,663**
Bayside Unit 3 Total	**13,953**	**161,814.0**	**11,597**	**$1,029,823**
Bayside Unit 4 Total	**16,093**	**183,659.0**	**11,412**	**$1,168,579**
Bayside Unit 5 Total	**16,004**	**189,085.0**	**11,815**	**$1,188,617**
Bayside Unit 6 Total	**9,835**	**112,492.0**	**11,438**	**$716,945**
Bayside Station Total	**6,916,593**	**50,887,017.5**	**7,357**	**$316,318,290**
System Total	18,294,070	170,833,743.8	9,338	$737,803,519

Source: Schedule A4 in Monthly Fuel Filing

2012 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Big Bend 1 Coal	2,154,188	22,572,810.6	10,479	$76,562,152
Big Bend 2 Coal	2,519,165	26,177,193.8	10,391	89,005,426
Big Bend 3 Coal	2,220,002	23,613,453.0	10,637	80,793,093
Big Bend 4 Coal	2,622,227	27,367,274.7	10,437	95,413,313
Big Bend Ignition Lt Oil	-	361,730.2	-	7,783,923
Big Bend Total Coal	**9,515,582**	**99,730,732.1**	**10,481**	**$349,557,907**
Big Bend CT 4 Gas	11,586	146,074.1	12,608	$785,127
Big Bend CT 4 Lt Oil	10	94.1	9,410	2,140
Big Bend CT 4 Total	**11,596**	**146,168.2**	**12,605**	**$787,267**
Big Bend Station Total	**9,527,178**	**99,876,900.3**	**10,483**	**$350,345,174**
Polk 1 Coal	1,174,951	12,576,817.8	10,704	$45,584,385
Polk 1 CT Lt Oil	19,964	203,663.5	10,202	4,803,138
Polk 1 Total	**1,194,915**	**12,780,481.3**	**10,696**	**$50,387,523**
Polk 2 Gas	91,436	1,105,145.0	12,087	$5,494,307
Polk 2 CT Lt Oil	156	2,169.0	0	50,029
Polk 2 Total	**91,592**	**1,107,314.0**	**12,090**	**$5,544,336**
Polk 3 Gas	109,763	1,266,028.0	11,534	$6,420,875
Polk 3 CT Lt Oil	112	2,160.3	0	47,536
Polk 3 Total	**109,875**	**1,268,188.3**	**11,542**	**$6,468,411**
Polk 4 Gas	**113,421**	**1,313,405.0**	**11,580**	**$6,779,807**
Polk 5 Gas	**122,162**	**1,325,783.0**	**10,853**	**$6,652,236**
Polk Station Total	**1,631,965**	**17,795,171.6**	**10,904**	**$75,832,313**
City of Tampa 1	(6)	0.0	0	$1,764
City of Tampa 2	-	0.0	0	1,764
City of Tampa Total	**(6)**	**0.0**	**0**	**$3,528**
Bayside ST 1	1,080,155	-	-	-
Bayside CT1A	674,242	7,627,964.0	11,313	$39,967,786
Bayside CT1B	682,664	7,638,919.0	11,190	40,704,316
Bayside CT1C	673,735	7,200,902.0	10,688	38,167,236
Bayside Unit 1 Total	**3,110,796**	**22,467,785.0**	**7,223**	**$118,839,338**
Bayside ST 2	1,361,441	-	-	-

2012 Total System Net Generation, MMbtu, Heat Rate and Fuel Cost				
Units	Net Generation (MWh)	Fuel Burned (MMbtu)	Average Net Heat Rate (Btu/KWh)	Fuel Cost ($)
Bayside CT2A	705,533	7,854,461.0	11,133	$42,756,306
Bayside CT2B	630,052	7,097,478.0	11,265	39,387,976
Bayside CT2C	591,890	6,672,535.0	11,273	35,050,175
Bayside CT2D	642,075	7,286,246.0	11,348	38,777,161
Bayside Unit 2 Total	3,930,991	28,910,720.0	7,355	$155,971,618
Bayside Unit 3 Total	18,951	211,503.0	11,161	$1,165,545
Bayside Unit 4 Total	19,258	211,538.0	10,984	$1,179,215
Bayside Unit 5 Total	19,086	212,222.0	11,119	$1,169,320
Bayside Unit 6 Total	20,447	224,847.0	10,997	$1,240,976
Bayside Station Total	7,119,529	52,238,615.0	7,337	$279,566,012
System Total	18,278,666	169,910,686.9	9,296	$705,747,027

Source: Schedule A4 in Monthly Fuel Filing

5. Please provide the calculations of the maximum potential GPIF incentive amount allowed per 1,000 kWh jurisdictional sales for each year since the implementation of the GPIF. As part of the response, please show the maximum allowed jurisdictional GPIF incentive dollars, jurisdictional sales, and the percentage for heat rate incentive and availability incentive respectively.

A. The requested information is provided on the following page and in a spreadsheet file. The maximum allowed GPIF incentive amount is calculated by multiplying the company's average annual total common equity by 25 basis points and dividing by the revenue expansion factor. The jurisdictional separation factor is calculated by dividing the jurisdictional sales by total sales. The maximum potential GPIF jurisdictional incentive amount allowed is calculated by multiplying the maximum allowed GPIF incentive amount by the jurisdictional separation factor, and the maximum potential GPIF incentive amount per 1,000 kWh jurisdictional sales is calculated by dividing the maximum potential GPIF jurisdictional incentive amount allowed by the jurisdictional sales (in MWh).

130001 Hearing Exhibits - 00562

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 5
PAGE 2 OF 2
FILED: MARCH 4, 2013

	A	B	C	(A*B)/C	D	E	D/E	(A*B)/C * D/E			J/D
Year	Common Equity ($)	25 Basis Points	Revenue Expansion Factor* (Rounded %)	Maximum allowed Incentive Calculated* ($)	Jurisdictional Sales (MWh)	Total Sales (MWh)	Jurisdictional Separation Factor (%)	Maximum allowed Jurisdictional Incentive Calculated ($)	Percent for EAF Incentive (%)	Percent for Heat Rate Incentive (%)	Maximum allowed Jurisdictional Incentive / 1,000 kWh ($/1,000 kWh)
1980/winter	No data	0.0025	No data	No data	No data	No data	No data	No data	No data	No data	No data
1980/summer	No data	0.0025	No data	No data	No data	No data	No data	No data	No data	No data	No data
1981/winter	301,236,000	0.0025	50.49%	1,491,628	4,664,696	4,664,696	100.00%	1,491,628	87.34	12.66	0.32
1981/summer	293,514,346	0.0025	50.49%	1,453,392	5,531,551	5,531,551	100.00%	1,453,392	73.42	26.58	0.26
1982/winter	310,501,713	0.0025	50.49%	768,755	4,972,930	4,972,930	100.00%	768,755	90.09	9.91	0.15
1982/summer	350,151,563	0.0025	50.50%	866,739	5,113,585	5,113,585	100.00%	866,739	84.00	16.00	0.17
1983/winter	411,699,174	0.0025	50.50%	1,019,090	4,913,980	4,913,980	100.00%	1,019,090	78.05	21.95	0.21
1983/summer	460,239,885	0.0025	50.50%	1,139,244	5,441,854	5,441,854	100.00%	1,139,244	71.97	28.03	0.21
1984/winter	496,490,512	0.0025	50.50%	1,228,976	5,358,930	5,358,930	100.00%	1,228,976	70.32	29.68	0.23
1984/summer	554,486,952	0.0025	50.57%	1,370,482	5,798,277	5,798,277	100.00%	1,370,482	70.10	29.90	0.24
1985/winter	581,963,164	0.0025	50.57%	1,438,392	5,614,425	5,614,425	100.00%	1,438,392	63.47	36.53	0.26
1985/summer	607,521,738	0.0025	50.57%	1,501,549	6,019,441	6,019,441	100.00%	1,501,549	59.70	40.30	0.25
1986/winter	637,236,965	0.0025	50.20%	1,586,720	5,599,869	5,599,869	100.00%	1,586,720	51.80	48.20	0.28
1986/summer	652,278,057	0.0025	50.20%	1,624,172	5,773,425	5,773,425	100.00%	1,624,172	35.65	64.35	0.28
1987/winter	659,023,534	0.0025	58.59%	1,405,947	5,427,700	5,427,700	100.00%	1,405,947	34.50	65.50	0.26
1987/summer	672,512,789	0.0025	61.38%	1,369,512	6,240,656	6,240,656	100.00%	1,369,512	22.64	77.36	0.22
1988/winter	682,269,179	0.0025	61.38%	1,389,380	5,710,131	5,710,131	100.00%	1,389,380	39.65	60.35	0.24
1988/summer	690,499,646	0.0025	61.38%	1,406,141	6,459,435	6,459,435	100.00%	1,406,141	54.53	45.47	0.22
1989/winter	699,115,000	0.0025	61.36%	1,424,289	5,899,739	5,899,739	100.00%	1,424,289	50.67	49.33	0.24
1989/summer	698,769,744	0.0025	61.36%	1,423,585	6,794,963	6,794,963	100.00%	1,423,585	43.10	56.90	0.21
1990/winter	698,946,363	0.0025	61.36%	1,423,945	6,063,297	6,063,297	100.00%	1,423,945	37.75	62.25	0.23
1990/summer	707,921,105	0.0025	61.36%	1,442,229	7,104,391	7,104,391	100.00%	1,442,229	41.11	58.89	0.20
1991/winter	717,376,456	0.0025	61.36%	1,461,492	6,211,845	6,223,232	99.82%	1,458,818	33.32	66.68	0.23
1991/summer	744,899,080	0.0025	61.36%	1,517,564	7,232,477	7,311,416	98.92%	1,501,179	35.73	64.27	0.21
1992/winter	782,296,783	0.0025	61.38%	1,593,078	6,337,041	6,413,283	98.81%	1,574,139	38.16	61.84	0.25
1992/summer	801,606,326	0.0025	61.38%	1,632,400	7,255,609	7,352,845	98.68%	1,610,813	38.75	61.25	0.22
1993/winter	804,450,034	0.0025	62.32%	1,613,596	6,208,356	6,297,245	98.59%	1,590,819	36.59	63.41	0.26
1993/summer	827,668,966	0.0025	61.37%	1,685,713	7,147,142	7,248,930	98.60%	1,662,043	41.87	58.13	0.23
1994/winter	852,420,095	0.0025	61.37%	1,736,124	6,398,506	6,412,522	99.78%	1,732,329	43.22	56.78	0.27
1994/summer	918,569,094	0.0025	61.37%	1,870,849	7,449,689	7,505,793	99.25%	1,856,865	49.58	50.42	0.25
1995/winter	953,527,765	0.0025	61.37%	1,942,050	6,572,598	6,583,711	99.83%	1,938,772	31.40	68.60	0.29
1995/summer	1,002,275,843	0.0025	61.37%	2,041,335	7,789,143	7,831,159	99.46%	2,030,383	39.58	60.42	0.26
1996/winter	1,037,899,631	0.0025	61.37%	2,113,890	7,128,371	7,156,645	99.60%	2,105,538	23.60	76.40	0.30
1996/summer	1,090,873,671	0.0025	61.37%	2,221,782	7,880,384	7,951,232	99.11%	2,201,985	47.93	52.07	0.28
1997/winter	1,118,087,052	0.0025	61.37%	2,277,208	6,866,832	6,924,931	99.16%	2,258,102	31.80	68.20	0.33
1997/summer	1,121,571,819	0.0025	61.37%	2,284,305	8,020,363	8,121,944	98.75%	2,255,735	52.51	47.49	0.28
1998/winter	1,123,610,573	0.0025	61.37%	2,288,457	6,973,189	7,019,436	99.34%	2,273,380	23.81	76.19	0.33
1998/summer	1,162,139,343	0.0025	61.37%	2,366,929	8,549,852	8,678,332	98.52%	2,331,887	46.92	53.08	0.27
1998/Oct-Dec	1,165,449,094	0.0025	61.37%	1,186,835	3,968,646	3,990,557	99.45%	1,180,318	36.76	63.24	0.30
1999	1,154,445,058	0.0025	61.37%	4,702,516	15,619,037	16,058,448	97.26%	4,573,840	37.57	62.43	0.29
2000	1,235,512,315	0.0025	61.37%	5,033,047	16,644,004	16,945,711	98.22%	4,943,437	42.62	57.38	0.30
2001	1,303,090,000	0.0025	61.38%	5,307,470	17,114,071	17,609,348	97.19%	5,158,193	31.88	68.12	0.30
2002	1,452,018,612	0.0025	61.38%	5,914,055	17,751,526	18,444,683	96.24%	5,691,803	41.97	58.03	0.32
2003	1,235,512,315	0.0025	61.37%	5,033,047	16,644,004	16,945,711	98.22%	4,943,437	50.10	49.83	0.30
2004	1,396,325,710	0.0025	61.38%	5,687,218	18,432,561	19,008,044	96.97%	5,515,033	57.47	42.53	0.30
2005	1,394,720,154	0.0025	61.38%	5,680,678	18,901,894	19,597,306	96.45%	5,479,099	68.54	31.46	0.29
2006	1,399,297,816	0.0025	61.38%	5,699,323	19,020,146	19,704,144	96.53%	5,501,480	66.67	33.33	0.29
2007	1,459,328,846	0.0025	61.38%	5,943,829	19,531,775	20,254,391	96.43%	5,731,771	55.49	44.51	0.29
2008	1,673,419,462	0.0025	61.38%	6,815,817	18,989,606	19,726,814	96.26%	6,561,104	54.34	45.66	0.35
2009	1,820,026,462	0.0025	61.17%	7,438,395	18,772,130	18,958,502	99.02%	7,365,272	53.03	46.97	0.39
2010	1,875,266,538	0.0025	61.17%	7,664,159	19,212,671	19,511,609	98.47%	7,546,737	45.60	54.40	0.39
2011	1,885,986,154	0.0025	61.17%	7,707,970	18,563,569	18,655,109	99.51%	7,670,147	28.17	71.83	0.41
2012	1,901,613,692	0.0025	61.17%	7,771,840	18,408,581	18,440,546	99.83%	7,758,368	24.19	75.81	0.42

* Note: Rounded and calculated data might vary slightly from actual true-up filing.

6. Please describe the various factors that could impact the efficient use of capital and over the long term, rates paid by customers. As part of the response, please provide the fuel and base rates breakdown for 1,000 kWh residential usage, the authorized ROE used to set base rates, the net energy for load, net MWh purchased power, net MWh generation, and T&D loss, for 1980, 1990, 2000, 2010, 2011, and 2012.

A. Tampa Electric plans, maintains and operates its generating units to serve customers through safe, reliable and efficient unit economic dispatch. The company does not take into consideration impacts to GPIF rewards and/or penalties as costs to maintain or improve unit reliability.

The requested data is provided below and in a spreadsheet file.

Year	Fuel Rate $/1,000 kWh	Base Energy Rate* ($/1,000 kWh)	Customer Charge ($/1,000 kWh)	ROE	Net Energy for Load (MWh)	Net Purchased Power MWh	Net Generation (MWh)	T&D Loss
1980**	$1.55	$53.46	$5.00	14.50%	8,527,927	4,894	9,020,777	501,160
1990	$26.17	$43.34	$7.00	14.50%	13,919,275	674,074	15,394,653	530,169
2000	$25.04	$43.42	$8.50	11.75%	18,151,565	2,691,658	17,283,041	851,162
2010	$41.67	$44.95	$10.50	11.25%	20,779,615	1,961,784	19,037,156	1,017,432
2011	$38.75	$44.95	$10.50	11.25%	19,207,080	1,178,134	18,294,070	679,494
2012	$38.40	$44.95	$10.50	11.25%	19,274,417	1,233,659	18,278,666	833,128

*In 1980 the base energy charge included a portion for fuel of $25.00.

**There are no available records prior to April 1980.

7. Please provide the projected GPIF heat rate target (Btus per kWh) and the projected MWh net generation of each GPIF unit for the years 2000 through 2012.

A. The requested information is provided on the following page and in a spreadsheet file.

130001 Hearing Exhibits - 00565

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 7
PAGE 2 OF 2
FILED: MARCH 4, 2013

Projected Heat Rate

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	10,127	10,118	10,111	10,533	10,708	10,853	10,841	10,971	10,908	10,774	10,785	10,676	10,468
BB2	10,061	9,895	9,815	10,111	10,384	10,672	10,510	10,484	10,693	10,396	10,481	10,350	10,272
BB3	10,197	9,932	10,036	10,132	10,278	10,663	10,923	11,090	10,657	10,751	10,627	10,582	10,614
BB4	9,976	9,944	10,089	10,028	10,272	10,350	10,672	10,828	10,837	10,598	10,661	10,538	10,549
PK1	N/A	10,146	10,087	10,382	10,569	10,342	10,497	10,428	10,607	10,707	10,661	9,820	10,220
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7,378	7,320	7,264	7,250	7,212	7,248
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7,359	7,378	7,409	7,311	7,316
Gannon 5	10,562	10,762	10,716	10,862	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	10,507	10,596	10,704	10,775	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Projected Net Generation MWh

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	2,535,127	2,401,066	2,567,761	1,159,670	2,149,249	1,622,779	2,007,784	2,256,616	2,145,174	2,430,945	1,798,746	2,646,940	2,682,450
BB2	2,882,763	2,852,590	2,382,612	1,425,819	2,286,905	1,799,508	2,582,864	2,517,748	2,468,665	1,883,282	2,242,698	2,108,120	2,541,330
BB3	2,428,251	2,566,868	2,164,880	1,240,217	2,263,934	1,873,211	1,601,740	1,748,851	1,527,678	1,579,317	2,473,022	2,344,680	2,292,860
BB4	3,050,647	3,054,988	2,678,252	1,751,579	2,798,348	2,691,339	2,605,120	2,107,873	2,652,938	2,560,140	2,492,431	2,859,320	2,640,420
PK1	N/A	1,612,905	1,632,916	762,613	1,728,783	1,519,143	1,162,329	1,779,998	1,599,527	1,855,886	1,719,902	1,518,210	1,577,360
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3,461,453	3,889,229	4,573,988	4,753,516	2,717,380	3,190,430
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4,711,118	4,653,531	4,001,171	4,438,630	4,142,250
Gannon 5	928,740	1,092,983	834,032	96,771	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	1,097,874	1,822,891	1,633,391	1,101,355	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

130001 Hearing Exhibits - 00566

8. Please provide the actual heat rate performance (Btus per kWh) and the actual MWh net generation of each GPIF unit for the years 2000 through 2012.

A. The requested information is provided on the following page and in a spreadsheet file.

130001 Hearing Exhibits - 00567

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 8
PAGE 2 OF 2
FILED: MARCH 4, 2013

Actual Heat Rate

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	10,231	10,530	10,519	10,884	10,599	10,964	11,058	11,159	11,067	10,405	10,257	10,630	10,467
BB2	9,925	10,079	10,398	10,522	10,396	10,610	10,451	10,466	10,658	10,143	10,107	10,260	10,356
BB3	9,866	9,917	10,275	10,678	10,507	10,767	11,130	10,929	11,008	10,623	10,610	10,406	10,595
BB4	9,896	10,197	10,488	10,297	10,444	10,690	11,103	11,325	10,838	10,501	10,410	10,295	10,420
PK1	N/A	10,254	10,565	10,547	9,928	10,331	10,442	10,684	10,582	10,652	11,030	10,430	10,619
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7,313	7,217	7,202	7,233	7,190	7,206
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7,329	7,326	7,412	7,301	7,286
Gannon 5	10,748	10,790	11,202	11,400	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	10,501	10,569	11,192	11,600	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Actual Net Generation MWh

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	2,422,093	1,951,834	2,225,758	2,117,534	2,035,146	2,022,145	1,860,915	2,540,074	2,418,010	1,789,648	1,978,198	2,591,165	2,154,188
BB2	2,721,652	2,279,335	1,646,679	2,018,456	2,155,075	2,068,306	2,727,592	2,669,756	2,292,003	1,158,803	2,197,115	1,879,639	2,519,165
BB3	2,479,258	2,370,413	1,776,925	1,986,711	2,199,378	1,792,250	2,155,150	1,594,602	1,418,472	2,535,949	2,434,151	2,305,767	2,220,002
BB4	3,090,089	2,597,308	2,846,741	2,482,684	2,701,968	2,550,708	2,677,159	1,804,048	2,598,972	2,825,537	2,376,875	2,641,737	2,622,227
PK1	N/A	1,389,733	1,712,425	1,306,867	1,687,278	1,273,707	1,588,838	1,615,842	1,497,590	1,337,813	1,664,556	1,483,473	1,194,915
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2,878,964	3,352,802	3,486,595	3,403,937	2,500,741	3,110,795
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4,012,900	4,781,843	4,599,661	4,359,263	3,930,992
Gannon 5	931,060	899,909	908,261	73,285	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	899,588	2,012,919	1,612,283	1,165,844	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

130001 Hearing Exhibits - 00568

9. Please provide the projected GPIF Equivalent Availability Factor (EAF) target and the MW capacity of each GPIF unit for the years 2000 through 2012.

A. The requested information is provided in the tables below and in a spreadsheet file.

Projected EAF

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	78.1	69.9	77.3	69.9	67.2	52.6	63.6	60.7	72.8	72.5	54.4	67.9	81.9
BB2	80.6	77.9	66.7	63.0	66.7	61.6	77.3	76.5	77.3	56.1	67.6	62.4	76.2
BB3	76.3	71.8	67.5	67.3	67.6	60.6	56.2	57.4	47.5	54.3	77.0	82.1	80.0
BB4	84.4	83.9	82.6	77.7	78.2	78.7	71.9	59.5	73.6	67.5	69.2	77.9	77.4
PK1	N/A	78.5	78	74.6	85.6	79.8	60.3	88.4	77.2	79.7	84.9	88.6	85.5
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	81.0	84.5	93.4	95.6	78.2	94.8
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	83.6	94.1	95.6	94.4	80.0
Gannon 5	75.3	68.4	56.7	71.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	72.2	67.4	63.9	75.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Projected Net MW

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	426	426	426	425	425	425	425	411	380	386	388	388	388
BB2	426	426	426	425	422	422	406	391	390	383	388	388	388
BB3	438	438	433	433	433	433	428	424	395	386	378	365	365
BB4	445	445	445	444	456	456	456	460	437	434	432	420	420
PK1	N/A	250	250	250	258	258	258	258	258	240	235	220	220
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	748	748	730	731	731	731
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	989	967	968	968	968
Gannon 5	237	237	218	217	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	382	382	382	381	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

10. Please provide the actual GPIF Equivalent Availability Factor (EAF) performance and the MW capacity for each GPIF unit for the years 2000 through 2012.

A. The requested information is provided in the tables below and in a spreadsheet file.

Actual EAF

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	74.3	63.9	71.1	61.2	67.9	56.6	57.4	73.4	76.6	58.7	58.6	80.7	67.8
BB2	83.2	73.4	52.4	58.1	70.4	74.2	79.7	76.8	72.2	33.8	69.2	52.7	76.7
BB3	79.6	71.3	53.8	60.1	68.8	53.4	60.8	48.2	48.4	79.8	79.7	75.2	69.3
BB4	86.1	82.3	84.3	72.0	74.8	73.8	76.7	55.1	74.4	68.6	69.8	77.8	76.9
PK1	N/A	82.8	84.6	67.5	89.4	65.9	85.6	85.6	79.0	80.3	91.0	77.0	71.5
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	87.0	93.5	95.0	95.1	77.6	94.7
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	82.8	94.8	94.3	91.6	80.3
Gannon 5	57.2	61.2	65.2	78.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	28.2	75.0	61.6	63.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Actual Net MW

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	421	419	419	423	423	423	411	394	382	383	388	388	388
BB2	421	419	419	418	418	403	391	394	387	382	388	388	388
BB3	438	436	433	431	431	426	420	417	388	384	365	365	365
BB4	445	444	444	454	455	455	459	449	426	420	423	420	415
PK1	N/A	250	250	256	257	257	257	257	252	236	220	220	220
BAY1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	732	730	731	731	731	731
BAY2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	967	968	968	968	968
Gannon 5	237	224	217	217	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gannon 6	382	379	379	270	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

130001 Hearing Exhibits - 00570

11. Please describe the improvement or decline in your company's heat rate performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

(a) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1980-89;

(b) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 1990-99;

(c) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2000-09;

(d) The annual average rate of improvement in heat rate and estimated fuel savings achieved due to improvement in heat rate performance in the period of 2010-12;

(e) The amount of capital and O&M required and deployed for the heat rate improvement in each period;

(f) The amount of net GPIF incentive payments for the heat rate performance in each period (annual and cumulative);

(g) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1980-89;

(h) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 1990-99;

(i) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2000-09;

(j) The annual average rate of change in the composite heat rate target (weighted by MWhs) set by the GPIF in the period of 2010-12;

130001 Hearing Exhibits - 00571

(k) The alternative analysis (if any).

A. The requested information is provided below and in a spreadsheet file.

(a) For the period 1980-1989, the annual average rate of improvement in heat rate was -0.08% and estimated fuel savings was 15.46%.

(b) For the period 1990-1999, the annual average rate of improvement in heat rate was -0.05% and estimated fuel savings was 63.26%.

(c) For the period 2000-2009, the annual average rate of improvement in heat rate was 0.84% and estimated fuel savings was 135.07%.

(d) For the period 2010-2012, the annual average rate of improvement in heat rate was -2.06% and estimated fuel savings was 73.82%.

(e) Tampa Electric does not maintain accounts of the amount of capital and O&M required and deployed for only heat rate improvements in each period. Capital and O&M spending occurs each year to maintain and improve unit availability, reliability, operability, and efficiency while taking into account unit performance, maintenance costs, operations costs, chemicals and consumables, and other life cycle costs.

(f) The data is provided in the spreadsheet file.

(g) For the period 1980-1989, the annual average rate of change in the composite heat rate target was 0.09%.

(h) For the period 1990-1999, the annual average rate of change in the composite heat rate target was -0.11%.

(i) For the period 2000-2009, the annual average rate of change in the composite heat rate target was 0.72%.

(j) For the period 2010-2012, the annual average rate of change in the composite heat rate target was -1.69%.

(k) The improvement or decline in Tampa Electric's heat rate performance for the base load units as a group can be determined from the data provided.

130001 Hearing Exhibits - 00572

However, due to the change in Tampa Electric's system generation mix, the data do not provide an apples-to-apples comparison over time. For example, in 2012 the base loaded units were Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, and the group had an average net operating heat rate of 9,898 Btu/kWh. These units' generation was a mixture of coal- and natural gas-fired generation. In contrast, the year 2000 base loaded units were Big Bend Units 1 through 4 and Gannon Units 5 through 6, all coal-fired units, with an average net operating heat rate of 10,054 Btu/kWh. No correlation can be made as to the heat rate improvement from 2000 to 2012 solely based on this example. The unit fuel type mix and system demand net operating factors vary from year to year based on fuel prices and system demand which directly affects the annual heat rate improvement analysis.

The company did not make a specific assessment in regards to the impact of planning, operations or maintenance activities on GPIF rewards and/or penalties. The results of the company's maintenance programs and practices are intended to maximize unit availability and performance. The company does not take into consideration impacts to GPIF rewards and/or penalties as costs to maintain or improve unit performance.

130001 Hearing Exhibits - 00573

12. Please describe the improvement or decline in your company's availability performance for the base load units as a group and describe the impact of Commission policies such as GPIF and the impact of your company's actions such as planning, operation, and maintenance. As part of the response, please provide the data and calculations supporting the following:

(a) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1980-89;

(b) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 1990-99;

(c) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2000-09;

(d) The annual average rate of improvement in availability factor and estimated fuel savings achieved due to improvement in availability factor performance in the period of 2010-12;

(e) The amount of capital and O&M required and deployed for the improvement in each period;

(f) The amount of net GPIF incentive payments for the availability factor performance in each period (annual and cumulative);

(g) The annual average rate of change in the composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1980-89;

(h) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 1990-99;

(i) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2000-09;

(j) The annual average rate of change in composite availability factor target (weighted by MW capacity) set by the GPIF in the period of 2010-12;

130001 Hearing Exhibits - 00574

(k) The alternative analysis (if any).

A. The requested information is provided below and in a spreadsheet file.

(a) For the period 1980-1989, the annual average rate of improvement in availability factor was -1.11% and estimated fuel savings was 187.49%

(b) For the period 1990-1999, the annual average rate of improvement in availability factor was 0.21% and estimated fuel savings was 54.67%.

(c) For the period 2000-2009, the annual average rate of improvement in availability factor was -0.30% and estimated fuel savings was 149.65%.

(d) For the period 2010-2012, the annual average rate of improvement in availability factor was -2.03% and estimated fuel savings was 71.40% for 2010-12.

(e) Tampa Electric does not maintain accounts of the amount of capital and O&M required and deployed for only availability improvements in each period. Capital and O&M spending occurs each year to maintain and improve unit availability, reliability, operability, and efficiency taking into account unit performance, maintenance costs, operations costs, chemicals and consumables, and other life cycle costs.

(f) The data is provided in the spreadsheet file.

(g) For the period 1980-1989, the annual average rate of change in the composite availability factor target was -0.88%.

(h) For the period 1990-1999, the annual average rate of change in the composite availability factor target was -0.04%.

(i) For the period 2000-2009, the annual average rate of change in the composite availability factor target was 1.90%.

(j) For the period 2010-2012, the annual average rate of change in the composite availability factor target was -8.20%.

130001 Hearing Exhibits - 00575

(k) The improvement or decline in Tampa Electric's availability factor for the base load units as a group can be determined from the data provided. However, due to the change in Tampa Electric's system generation mix, the data do not provide an apples-to-apples comparison over time. For example, in 2012 the base loaded units were Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, and the group had an actual availability factor of 79.4%. These units' generation was a mixture of coal-fired and natural gas-fired generation. In contrast, the year 2000 base loaded units were Big Bend Units 1 through 4 and Gannon Units 5 through 6, all coal-fired units, with an actual availability factor of 77.9%. No correlation can be made as to the availability improvement from 2000 to 2012 solely based on this example. The unit fuel type mix and planned outage factors vary from year to year based on fuel prices and planned major maintenance, which directly affects the annual availability improvement analysis.

The company did not make a specific assessment of the impact of planning, operations or maintenance activities on GPIF rewards and/or penalties. The results of the company's maintenance programs and practices are intended to maximize unit availability and performance. The company does not take into consideration impacts to GPIF rewards and/or penalties as costs to maintain or improve unit reliability.

130001 Hearing Exhibits - 00576

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is a Director, Regulatory Affairs, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1-12) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 1st day of March, 2013.

Penelope Rusk

Sworn to and subscribed before me this 1ST day of March, 2013.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2015

My Commission expires _____

84

TECO's Responses to Staff's Second Set of Interrogatories (Nos. 13-23)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 84
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0578-0598]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: March 6, 2013

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 13-23)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 13-23) propounded and served on February 4, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 13-23)

Number	Witness	Subject	Bates Stamped Page
13	Caldwell	For each Request for Proposal (RFP) for coal issued in 2012 by Tampa Electric Company (TECO), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.	1
14	Caldwell	Please describe the action taken for each bid identified in response to Interrogatory No. 13. Include in your response an explanation of the evaluation process and how successful proposals were selected.	4
15	Caldwell	During 2012, did TECO experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.	5
16	Caldwell	For each RFP for natural gas issued in 2012 by TECO, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.	6
17	Caldwell	Please describe the action taken for each bid identified in response to Interrogatory No. 16. Include in your response an explanation of the evaluation process and how successful proposals were selected.	11
18	Caldwell	In 2012, did TECO participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response and identify the pipeline companies.	12
19	Caldwell	In 2012, did TECO participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.	13
20	Smith	For each RFP for light oil issued in 2012 by TECO, list the bids received.	14
21	Caldwell	Please describe the action taken for each bid identified in response to Interrogatory No. 20. Include in your response an explanation of the evaluation process and how successful proposals were selected.	15

22	Smith	For each RFP for purchased power issued in 2012 by TECO, list the bids received.	16
23	Smith	Please describe the action taken for each bid identified in response to Interrogatory No. 22. Include in your response an explanation of the evaluation process and how successful proposals were selected.	17

Brent Caldwell
Director, Origination & Market Services

Benjamin Smith
Manager, Strategic Fuels & Power Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 13
PAGE 1 OF 3
FILED: MARCH 6, 2013

13. For each Request for Proposal (RFP) for coal issued in 2012 by Tampa Electric Company (TECO), list the bids received. For each bid, include the supplier, tonnage bid, coal quality, and delivered price information, as well as the method and route of delivery.

A. Tampa Electric issued three RFP's for solid fuel in 2012. Please see the tables below for the list of bids received.

GEN 2013-01

		Coal Quality					Delivered Price				
Supplier	Tonnage Bid	Btu/lb	Ash %	Sulfur %	Moisture %	Chlorine %	$/Ton	Cents per MMBtu	Delivery Method	Delivery Route	Awarded
Armstrong Coal									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Armstrong Coal									Railcar	PAL Rail / CSX Rail	
Knight Hawk Coal									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Partiot Coal Sales									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	Yes
Foresight Coal Sales									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Foresight Coal Sales									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Foresight Coal Sales									Railcar	CSX Rail	
Alliance Coal, LLC									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Alliance Coal, LLC									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Alliance Coal, LLC									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Alliance Coal, LLC									Railcar	CSX Rail	
The American Coal Company									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Traxys North America									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Peabody COALSALES,									River Barge, Ocean	Mississippi River / Gulf	

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 13
PAGE 2 OF 3
FILED: MARCH 6, 2013

	Coal Quality						Delivered Price				
Supplier	Tonnage Bid	Btu/lb	Ash %	Sulfur %	Moisture %	Chlorine %	$/Ton	Cents per MMBtu	Delivery Method	Delivery Route	Awarded
LLC									Vessel	Delivery	
Peabody COALSALES, LLC									Railcar	INRD / CSX Rail	Yes
Peabody COALSALES, LLC									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Lafayette Energy Co.									Railcar	CSX Rail	
White Oak Resources									Railcar	EVWR / CSX Rail	
Sunrise Coal, LLC									Railcar	CSX Rail	
Solar Sources									Railcar	CSX Rail	
Consol Energy									Railcar	CSX Rail	

Polk LS 2013-01

	Coal Quality						Delivered Price				
Supplier	Tonnage Bid	Btu/lb	Ash %	Sulfur %	Moisture %	Chlorine %	$/Ton	Cents per MMBtu	Delivery Method	Delivery Route	Awarded
Peabody COALTRADE									Ocean Vessel	Texas - Florida	
Peabody COALSALES									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Oxbow Mining									Rail , Ocean Vessel	Colorado - Texas - Florida,	
Arch									Railcar	CSX Rail	
Glencore									Ocean Vessel	Columbia SA - Florida	Yes

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 13
PAGE 3 OF 3
FILED: MARCH 6, 2013

Polk PC 2013-01

		Pet Coke Quality					Delivered Price				
Supplier	Tonnage Bid	Btu/lb	Ash %	Sulfur %	Moisture %	Chlorine %	$/Ton	Cents per MMBtu	Delivery Method	Delivery Route	Awarded
KOCH Carbon	[redacted]								River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Maceachern Energy									Ocean Vessel	Delaware - Florida,	
TCP Petcoke									River Barge, Ocean Vessel	Mississippi River / Gulf Delivery	
Oxbow Carbon									Ocean Vessel	Alabama - Florida	
Valero Marketing									Ocean Vessel	Louisana - Florida	Yes

14. Please describe the action taken for each bid identified in response to Interrogatory No. 13. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. As a result of the Gen 2013-01 bid solicitations identified in Tampa Electric's response to Interrogatory No.13, Tampa Electric purchased a total of 260,000 tons for 2013. As a result of the Polk LS 2013-01 and the Polk PC 2013-01 Tampa Electric purchased a combined total of 900,000 tons for 2013 and 2014. All bids were evaluated on a total delivered cost per MMBtu basis. To identify a short list of qualifying bidders, Tampa Electric also evaluated bids based on projected commodity and transportation costs, quality, proposed terms and conditions, blending impacts, and supplier reliability. Qualifying bids accounting for operational impacts, containing acceptable quality, terms and conditions and supplier reliability as specified in the RFP were considered. Once qualifying bids were identified, Tampa Electric selected the quality-adjusted lowest priced alternative on a utilized basis to award a contract.

130001 Hearing Exhibits - 00585

15. During 2012, did TECO experience any detention and demurrage charges, or any transportation constraints for coal deliveries? If so, please explain your response and state the charges by event.

A. Yes. During 2012, Tampa Electric's experienced detention, demurrage charges, and transportation constraints for coal deliveries.

Detention and demurrage are common charges associated with transportation of bulk commodities. These charges reflect the natural operational and timing-sensitive nature of loading, unloading and transferring bulk commodities. Detention and demurrage charges are part of the overall negotiation; sometimes the detention and demurrage may be embedded in a higher rate and sometimes the charges are stated separately. Tampa Electric's contracts contain provisions that provide for detention and demurrage charges in the event that contractual guarantees for either loading or unloading of coal are not met. Demurrage and detention are charges payable to the owner of transportation equipment if there is an inability to load or discharge within the time agreed upon within the contract. In 2012, Tampa Electric incurred demurrage for barge loadings at the docks, vessel loadings at terminals, and vessel unloading at the stations.

130001 Hearing Exhibits - 00586

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 16
PAGE 1 OF 5
FILED: MARCH 6, 2013

16. For each RFP for natural gas issued in 2012 by TECO, list the bids received. For each bid, include the supplier, volume bid, and delivered price information, as well as the primary pipeline delivered by.

A. Please see the table below for all bids received in response to Tampa Electric's RFP.

Supplier	Volume/day	Nymex Offer	Index Offer	Gas Daily	Pipeline
[redacted]					

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 16
PAGE 2 OF 5
FILED: MARCH 6, 2013

Supplier	Volume/day	Nymex Offer	Index Offer	Gas Daily	Pipeline

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 16
PAGE 3 OF 5
FILED: MARCH 6, 2013

Supplier	Volume/day	Nymex Offer	Index Offer	Gas Daily	Pipeline

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 16
PAGE 4 OF 5
FILED: MARCH 6, 2013

Supplier	Volume/day	Nymex Offer	Index Offer	Gas Daily	Pipeline

REDACTED

Supplier	Volume/day	Nymex Offer	Index Offer	Gas Daily	Pipeline

17. Please describe the action taken for each bid identified in response to Interrogatory No. 16. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. Tampa Electric issued one Requests for Proposals ("RFP") for natural gas supply in 2012. The RFP was issued in October 2012. Tampa Electric sent the RFP to approximately 95 qualified suppliers. In response to the RFP, Tampa Electric received approximately 208 gas supply package options from 30 gas supply respondents. Each gas supply option was evaluated based on price, pipeline, receipt point, supply type, firmness, time frame, and special conditions. Special conditions included the following items:

- pipeline optionality, or the ability to move supply from one pipeline to another at Tampa Electric's option;
- volume flexibility, the ability to adjust the daily baseload gas volume at the beginning of each month; and
- pricing conversion, an indexed gas price that can be converted to a fixed price at Tampa Electric's request.

Tampa Electric grouped the packages by time frame (e.g., winter packages), gas supply type (e.g., baseload, swing, or peaking), and pipeline. For each group, the packages were ranked by price. Finally, special provisions and strategic considerations related to price and supplier risk were considered. The company selected the lowest cost supply packages while accounting for needed reliability, optionality and flexibility. Tampa Electric contacted the selected suppliers to execute a deal confirmation. If an agreement could not be reached, the next best vendor was contacted.

As a result of the October 2012 RFP, 17 vendors were awarded a total of 100,000 to 130,000 MMBtu per day depending on the season. The selected packages included baseload, Take or Release, Daily Swing, various time frames and different pipelines.

18. In 2012, did TECO participate in any capacity discussions or bid for any firm pipeline capacity during "open season?" Please explain your response and identify the pipeline companies.

A. Tampa Electric did not participate in any capacity discussions or bids for pipeline capacity in 2012.

19. In 2012, did TECO participate in any discussions or bid for any firm gas storage capacity? Please explain your response and identify the gas storage providers.

A. Tampa Electric did not participate in any firm gas storage capacity discussions or bids for firm gas storage capacity in 2012.

130001 Hearing Exhibits - 00594

20. For each RFP for light oil issued in 2012 by TECO, list the bids received.

A. Tampa Electric did not issue a bid for light oil in 2012.

130001 Hearing Exhibits - 00595

21. Please describe the action taken for each bid identified in response to Interrogatory No. 20. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. As previously stated in the company's response to Interrogatory No. 20, Tampa Electric did not issue a bid for light oil in 2012.

130001 Hearing Exhibits - 00596

22. For each RFP for purchased power issued in 2012 by TECO, list the bids received.

A. In March 2012, Tampa Electric issued an RFP to solicit competitive offers to satisfy the company's projected capacity and energy requirements for comparison to Tampa Electric's planned generating unit, Polk 2-5 Combined Cycle Conversion.

RFP Summary of Proposals

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Company	TEC				
Type	Intermediate	Intermediate PPA	Sale of peaking facility	Peaking PPA	Peaking PPA
Technology	4x1 CC Conversion	2x1 CC	(2) 7FA CTs	New Build 7FA.05 CT	New Build 7FA.05 CT
Plant Name	Polk Power Station				
Capacity (MW)	459(S)/463(W)				
Start Year	2017	2017	2013	2017	2017
Term (years)	N/A	10	N/A	10	15
HR (Btu/kWh)	7,062				

The company received four proposals as referenced, above. The bids were for either an intermediate (e.g. combined cycle ("CC")) or peaking (e.g. combustion turbine ("CT")) product.

130001 Hearing Exhibits - 00597

23. Please describe the action taken for each bid identified in response to Interrogatory No. 22. Include in your response an explanation of the evaluation process and how successful proposals were selected.

A. As required by the Power Plant Siting Act, Tampa Electric followed the requirements of 25-22.080 – 25-22.082, Florida Administrative Code. The company selected the Polk 2-5 Combined Cycle Conversion, which was approved by the Florida Public Service Commission.

The proposals went through an initial screening and economic ranking. From the initial screening, the economically viable proposals went through a more rigorous economic analysis assuming it serves Tampa Electric's customers future load requirements. These results were compared on a cumulative present value of revenue requirements (CPVRR) basis and ranked.

Prior to a final selection, the proposals also went through a non-economic evaluation. This evaluation included factors such as environmental considerations, water supply, technical and financial viability, operational attributes, renewable energy integration potential, project execution, transmission system benefits, dual fuel capability, dispatchability and commitment benefits.

The company selected its self-build option and this selection was confirmed by an independent consultant, Sedway Consulting, hired by the company using their own proprietary model.

130001 Hearing Exhibits - 00598

85

TECO's Responses to Staff's Third Set of Interrogatories (Nos. 24-34)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 85
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0599-0618]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: March 21, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NOS. 24-34)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 24-34) propounded and served on February 19, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 24-34)

Number	Witness	Subject	Bates Stamped Page
24	Smith	Please state whether performance improvement in availability and heat rate also increases the company's ability or opportunity to make off-system economy sales. As part of the response, please provide the MWh and dollar amounts of off-system economy sales by year for 2006 through 2012.	1
25	Smith	Please state whether performance degradation in availability and heat rate also increases the company's ability or opportunity to make off-system economy purchases? As part of the response, please provide the MWh and dollar amounts of off-system economy purchases by year for 2006 through 2012.	2
26	Buckley	Please provide the data in the following table.	3
27	Buckley	Please provide the data in the following table.	4
28	Buckley	Please provide the EFOR (Equivalent Forced Outage Rate) data for each GPIF unit by year for 2006 through 2012.	5
29	Buckley	Please describe the method of estimating the maximum fuel savings reported in TECO's GPIF projection and actual filings. As part of the response, please identify the source and reasoning for the use of the production simulation model for the actual filings.	6
30	Buckley	Please provide a comparison of the projected and actual monthly fuel cost for 2012 and factors contributing to the difference. As part of the response, please provide the data and calculations supporting the following: a) Difference in average monthly heat rates for the aggregated GPIF units, b) Difference in average monthly heat rates for the system (including non-GPIF units), c) Difference in average monthly fuel price ($/mmBtu) for the aggregated GPIF units, d) Difference in average monthly fuel price	7

		($/mmBtu) for the system (including non-GPIF units), e) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model, f) Difference in monthly fuel cost dollars for the system (including non-GPIF units), caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model, g) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model, and h) Difference in monthly fuel cost dollars for system (including non-GPIF units), caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model.	
31	Buckley	Please state the manner in which the GPIF mechanism may be modified to achieve the same fuel savings and efficiency objective that will allow fuel savings to be calculated and verified without the use of production simulation model.	11
32	Buckley	Please state the manner in which your company sets performance expectations for individual unit production efficiency, measures performance against expectations, and calibrates incentives for management accountability for the individual plant.	12

33	Buckley	Describe the manner in which your company sets performance expectations for total system production efficiency, measures performance against expectations, and calibrates incentives for management accountable for the total system.	13
34	Buckley	Describe the manner in which your company evaluates the effectiveness of its incentive mechanism, makes improvement in the mechanism, and promotes sharing best practices that improve production efficiency?	14

Brian Buckley
Manager, Compliance & Performance

Benjamin Smith
Manager, Strategic Fuels & Power Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

Interrogatory Nos. 24-34 regard the investigation of the effectiveness of the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

24. Please state whether performance improvement in availability and heat rate also increases the company's ability or opportunity to make off-system economy sales. As part of the response, please provide the MWh and dollar amounts of off-system economy sales by year for 2006 through 2012.

A. Tampa Electric's ability to make off-system economy sales depends on a variety of factors, one of which is its own resources. The factors include Tampa Electric system load, statewide loads, relative fuel prices, the price of economy energy within the power market, the number of sellers and purchasers, and the availability of electric transmission capability. These factors are constantly changing. However, if conditions were favorable for making off-system economy sales and all factors stay static—with the exception of improved availability and heat rate of Tampa Electric resources—the company could recognize an increase in off-system sales opportunities.

The requested information is provided in the table below.

Economy Sales		
Year	MWh	Revenues*
2006	70,180	$4,364,210.86
2007	75,426	$4,351,762.52
2008	132,051	$8,700,008.97
2009	240,131	$12,645,817.46
2010	164,872	$10,824,409.85
2011	71,486	$3,232,338.37
2012	34,129	$991,413.08

** Source: Schedule A6, Column (8)*

130001 Hearing Exhibits - 00604

25. Please state whether performance degradation in availability and heat rate also increases the company's ability or opportunity to make off-system economy purchases? As part of the response, please provide the MWh and dollar amounts of off-system economy purchases by year for 2006 through 2012.

A. As is the case of making off-system economy sales, Tampa Electric's ability to make off-system economy purchases depends on a variety of factors, one of which is its own resources. The factors include Tampa Electric system load, statewide loads, relative fuel prices, the price of economy energy within the power market, the number of sellers and purchasers, and the availability of electric transmission capability. These factors are constantly changing. However, if conditions were favorable for making off-system economy purchases and all factors stay static—with the exception of degraded availability and heat rate of Tampa Electric resources—the company could recognize an increase in off-system purchases opportunities.

The requested information is provided in the table below.

Economy Purchases		
Year	MWh	Costs*
2006	1,271,295.4	$106,136,755.34
2007	1,501,624.0	$120,774,851.22
2008	971,887.0	$103,747,406.41
2009	478,338.0	$28,643,050.77
2010	554,000.0	$42,113,021.40
2011	308,976.0	$18,733,706.86
2012	259,780.0	$9,337,959.38

* *Source: Schedule A9, Column (8)(B)*

26. Please provide the data in the following table.

Year	GPIF Total Points	GPIF Reward / Penalty	System Fuel Cost at Target Level of Performance	System Fuel Cost at Actual Level of Performance	Fuel Savings / Costs
2006					
2007					
2008					
2009					
2010					
2011					
2012					

A. The requested information is provided in the table below.

Year	GPIF Total Points	GPIF Reward / Penalty	System Fuel Cost at Target Level of Performance	System Fuel Cost at Actual Level of Performance	Fuel Savings / Costs
2006	2.617	$1,439,819	$959,068,300	$930,606,100	$28,462,200
2007	-1.482	($849,634)	$1,079,796,600	$1,088,349,200	($8,552,600)
2008	1.888	$1,239,009	$1,117,430,900	$1,103,610,100	$13,820,800
2009	2.486	$1,830,855	$1,492,425,100	$1,461,707,300	$30,717,800
2010	2.722	$2,054,696	$936,879,400	$918,683,700	$18,195,700
2011	-0.701	($538,019)	$872,944,300	$875,427,900	$2,483,600
2012	-1.513	($1,173,753)	$842,493,200	$846,894,000	($4,400,800)

130001 Hearing Exhibits - 00606

27. Please provide the data in the following table.

Year	Total EAF Points	EAF Reward / Penalty	System Fuel Cost at Target Level of EAF Performance	System Fuel Cost at Actual Level of EAF Performance	Fuel Savings / Costs due to EAF
2006					
2007					
2008					
2009					
2010					
2011					
2012					

A. The requested information is provided in the table below.

Year	Total EAF Points	EAF Reward / Penalty	System Fuel Cost at Target Level of EAF Performance	System Fuel Cost at Actual Level of EAF Performance	Fuel Savings / Costs due to EAF
2006	3.508	$1,929,973	$959,068,300	$926,391,400	$32,676,900
2007	-0.820	($470,214)	$1,079,796,600	$1,084,489,800	($4,693,200)
2008	1.797	$1,179,070	$1,117,430,900	$1,104,064,000	$13,366,900
2009	1.638	$1,206,695	$1,492,425,100	$1,466,832,900	$25,592,200
2010	2.233	$1,685,045	$936,879,400	$920,331,400	$16,548,000
2011	-0.940	($720,969)	$872,944,300	$871,136,900	$1,807,400
2012	-0.998	($774,155)	$842,493,200	$845,363,200	($2,870,000)

28. Please provide the EFOR (Equivalent Forced Outage Rate) data for each GPIF unit by year for 2006 through 2012.

A. The requested information is provided in the table below.

	Equivalent Forced Outage Rate ("EFOR")						
Unit	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Big Bend Unit 1	26.3	20.6	18.5	21.5	15.1	11.4	32.1
Big Bend Unit 2	14.6	15.1	17.7	42.0	25.4	27.4	14.3
Big Bend Unit 3	28.4	33.7	29.2	12.2	11.8	16.9	20.7
Big Bend Unit 4	15.9	21.8	21.0	12.9	14.6	13.9	13.2
Polk Unit 1	8.5	10.4	12.8	11.1	4.0	17.2	19.4
Bayside Unit 1	8.1	0.8	0.2	0.2	0.4	0.7	0.4
Bayside Unit 2	1.1	0.8	0.8	0.5	0.2	0.2	1.4

130001 Hearing Exhibits - 00608

29. Please describe the method of estimating the maximum fuel savings reported in TECO's GPIF projection and actual filings. As part of the response, please identify the source and reasoning for the use of the production simulation model for the actual filings.

A. For Tampa Electric's GPIF projection filing, a baseline production costing analysis was performed to calculate the total system fuel cost should all units operate at their target heat rate and target availability for the period. This total system fuel cost is shown in Document No. 2 of Tampa Electric's 2013 GPIF projection filing on page 6, column 2, filed on September 1, 2012. From there, multiple production cost simulations are performed to calculate the total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each unit operating at maximum improvement in average net operating heat rate. The estimated maximum fuel savings by unit can be found on page 6, column 4 of Document No. 2.

For Tampa Electric's GPIF actual filing, the source of the estimated maximum fuel savings is the Tampa Electric's GPIF projection filing. The estimated maximum fuel savings is scaled based on the generating performance incentive points for each individual unit and is summarized in Document No. 1 of Tampa Electric's GPIF true-up filing, page 5, last column, filed on March 15, 2013. The production cost model is not used in Tampa Electric's GPIF true-up filing.

130001 Hearing Exhibits - 00609

30. Please provide a comparison of the projected and actual monthly fuel cost for 2012 and factors contributing to the difference. As part of the response, please provide the data and calculations supporting the following:

a) Difference in average monthly heat rates for the aggregated GPIF units,

b) Difference in average monthly heat rates for the system (including non-GPIF units),

c) Difference in average monthly fuel price ($/mmBtu) for the aggregated GPIF units,

d) Difference in average monthly fuel price ($/mmBtu) for the system (including non-GPIF units),

e) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model,

f) Difference in monthly fuel cost dollars for the system (including non-GPIF units), caused by factors outside the company's control such as fuel price relationships and environmental limitations. Describe these factors and demonstrate whether the difference can be calculated and verified without the use of production simulation model,

g) Difference in monthly fuel cost dollars for the aggregated GPIF units caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model, and

h) Difference in monthly fuel cost dollars for system (including non-GPIF units), caused by factors within the company's operational control or other factors due to resource planning such as resource additions. Describe these factors, actions taken by the company, and demonstrate whether the difference can be calculated and verified without the use of production simulation model.

130001 Hearing Exhibits - 00610

A. a) The requested information is provided in the table below.

GPIF Units Heat Rate
(Btu/kWh)

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
GPIF Units Projected	9,498	9,471	9,776	9,072	9,097	9,130	9,110	9,079	8,994	9,238	9,501	9,229
GPIF Units Actual	9,399	9,585	9,538	8,936	8,723	8,798	8,941	9,272	9,231	9,416	9,624	9,532
Difference	(99)	114	(238)	(136)	(374)	(332)	(169)	193	237	178	123	303

Source: 2012 Projection Filed September 1, 2011 and Monthly Schedule A4

b) The requested information is provided in the table below.

System Heat Rate
(Btu/kWh)

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Total System Projected	9,495	9,476	9,798	9,085	9,092	9,131	9,115	9,109	9,010	9,257	9,498	9,215
Total System Actual	9,423	9,619	9,608	9,120	8,887	8,880	9,024	9,312	9,284	9,434	9,637	9,584
Difference	(72)	143	(190)	35	(205)	(251)	(91)	203	274	177	139	369

Source: 2012 Projection Filed September 1, 2011 and Monthly Schedule A4

130001 Hearing Exhibits - 00611

c) The requested information is provided in the table below.

GPIF Units Fuel Price
($/mmBtu)

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
GPIF Units Projected	4.34	4.40	4.21	4.62	4.41	4.46	4.47	4.47	4.57	4.48	4.39	4.60
GPIF Units Actual	4.19	4.20	4.08	4.19	4.00	4.04	4.16	4.09	4.21	4.03	4.05	4.07
Difference	(0.15)	(0.21)	(0.13)	(0.43)	(0.41)	(0.42)	(0.31)	(0.38)	(0.36)	(0.45)	(0.34)	(0.54)

Source: 2012 Projection Filed September 1, 2011 and Monthly Schedule A4

d) The requested information is provided in the table below.

Total System Fuel Price
($/mmBtu)

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Total System Projected	4.35	4.44	4.30	4.64	4.43	4.48	4.49	4.52	4.60	4.52	4.40	4.61
Total System Actual	4.26	4.24	4.14	4.26	4.06	4.09	4.17	4.13	4.24	4.06	4.08	4.12
Difference	(0.09)	(0.20)	(0.16)	(0.39)	(0.37)	(0.39)	(0.32)	(0.39)	(0.35)	(0.46)	(0.32)	(0.49)

Source: 2012 Projection Filed September 1, 2011 and Monthly Schedule A4

e) The requested information is provided in the table below. The primary reason for the difference in monthly fuel costs is lower than projected fuel prices. The monthly fuel cost projections are developed in a production cost model based on a projected load forecast which varies from actual energy demand mainly due to weather. Due to these and other factors, the actual to projected differences cannot be calculated without using a production cost model.

GPIF Units Fuel Costs
($000)

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
GPIF Units Projected Costs	$61,663	$52,908	$51,313	$59,282	$68,213	$73,874	$77,077	$77,979	$72,788	$65,589	$58,368	$63,831
GPIF Units Actual Costs	$54,610	$51,370	$52,989	$48,218	$51,836	$56,724	$65,714	$70,210	$65,515	$59,989	$48,147	$49,434
Difference	($7,053)	($1,538)	$1,676	($11,063)	($16,378)	($17,150)	($11,364)	($7,769)	($7,273)	($5,600)	($10,222)	($14,397)

Source: 2012 Projection Filed September 1, 2011 and Monthly Schedule A4

f) The requested information is provided in the table below. The primary reason for the difference in monthly fuel costs is lower than projected fuel prices. The monthly fuel cost projections are developed in a production cost model based on a projected load forecast which varies from actual energy demand mainly due to weather. Due to these and other factors, the actual to projected differences cannot be calculated without using a production cost model.

Total System Fuel Costs
($000)

	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
Total System Projected Costs	$62,126	$54,087	$53,679	$60,588	$69,213	$75,259	$78,610	$81,109	$74,597	$67,847	$58,962	$63,950
Total System Actual Costs	$55,684	$52,920	$56,158	$54,187	$56,980	$59,598	$68,558	$72,328	$67,858	$60,935	$48,982	$51,559
Difference	($6,442)	($1,167)	$2,479	($6,401)	($12,234)	($15,660)	($10,052)	($8,780)	($6,739)	($6,911)	($9,980)	($12,391)

Source: 2012 Projection Filed September 1, 2011 and Monthly Schedule A4

g) This cannot be determined. There were no resource additions in 2012.

h) This cannot be determined. There were no resource additions in 2012.

130001 Hearing Exhibits - 00613

31. Please state the manner in which the GPIF mechanism may be modified to achieve the same fuel savings and efficiency objective that will allow fuel savings to be calculated and verified without the use of production simulation model.

A. The GPIF mechanism does not need to be modified. There is no way to target unit fuel costs without using a production cost model. Additionally, projected fuel savings must be calculated using a production cost model. Tampa Electric reports the actual fuel cost by unit on Schedule A4.

130001 Hearing Exhibits - 00614

32. Please state the manner in which your company sets performance expectations for individual unit production efficiency, measures performance against expectations, and calibrates incentives for management accountability for the individual plant.

A. Tampa Electric sets unit performance expectations for GPIF on an annual basis as defined in the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006. The most recent unit availability data, July through June annual period, formed the basis of the target development. Using one year of historical data, the Equivalent Availability Factor targets are set removing forced outage hours greater than two standard deviations above the three year outage duration mean.

Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Tampa Electric measures unit performance against annual targets and submits a table and outage listing to the FPSC monthly.

Management accountability occurs at each station based on Station Goals including safety, environmental, O&M and capital budgets, preventative maintenance work complete, continuous improvement projects complete and community involvement. GPIF rewards or penalties are not included in management incentives.

33. Describe the manner in which your company sets performance expectations for total system production efficiency, measures performance against expectations, and calibrates incentives for management accountable for the total system.

A. There are no total system GPIF targets. All targets are set by individual units as described in Tampa Electric's response to Staff's Third Set of Interrogatories, No. 32.

34. Describe the manner in which your company evaluates the effectiveness of its incentive mechanism, makes improvement in the mechanism, and promotes sharing best practices that improve production efficiency?

A. Tampa Electric believes that the GPIF incentive mechanism is effective and rewards our customers every year. No improvements are necessary to the GPIF mechanism as Tampa Electric only receives rewards when there is a substantial fuel savings to our customers. This is portrayed in Tampa Electric's responses to Staff's Third Set of Interrogatories, No. 26 and 27.

Tampa Electric has a Continuous Improvement Program and is a participant in the Electric Power Research Institute ("EPRI") Operational Best Practices Program.

130001 Hearing Exhibits - 00617

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Third Set of Interrogatories, (Nos. 24-34) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 20th day of March, 2012.

Penelope Rusk

Sworn to and subscribed before me this 20th day of March, 2012.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

86

TECO's Responses to Staff's Fourth Set of Interrogatories (No. 35)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 86
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0619-0623]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: APRIL 29, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FOURTH SET OF INTERROGATORIES (NO. 35)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 35) propounded and served on March 29, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S FOURTH SET OF INTERROGATORIES (NO. 35)

Number	Witness	Subject	Bates Stamped Page
35	Brent Caldwell Benjamin Smith Penelope Rusk	In its 2013 actual/estimated or 2014 projected testimony, will Tampa Electric propose any new contract, new capital project, or other new cost for fuel or capacity cost recovery? If so, please list all such proposals.	1

Brent Caldwell
Director, Origination & Marketing Services

Penelope Rusk
Administrator, Rates

Benjamin Smith
Manager, Strategic Fuels and Power Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

35. In its 2013 actual/estimated or 2014 projected testimony, will Tampa Electric propose any new contract, new capital project, or other new cost for fuel or capacity cost recovery? If so, please list all such proposals.

A. Currently, Tampa Electric does not expect to have any new contracts or other new costs to include for fuel or capacity cost recovery for the 2013 actual/estimated or 2014 projected testimony. Tampa Electric continually seeks new opportunities and enters into contracts that benefit customers, but it is not in any current negotiations. Similarly, the company evaluates new capital projects that may result in fuel savings and could be proposed for fuel clause cost recovery. Currently, the company is evaluating the conversion of Big Bend Station ignition from oil to natural gas; however, the evaluation is not complete and, at this time, no determination can be made as to whether or when the project might be proposed for fuel cost recovery.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fourth Set of Interrogatories, (No. 35) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 24th day of April, 2013.

Penelope Rusk

Sworn to and subscribed before me this 25th day of April, 2013.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

87

TECO's Responses to Staff's Fifth Set of Interrogatories (Nos. 36-37)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 87
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0624-0629]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: MAY 29, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIFTH SET OF INTERROGATORIES (NO. 36-37)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 36-37) propounded and served on April 29, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S FIFTH SET OF INTERROGATORIES (NO. 36-37)

Number	Witness	Subject	Bates Stamped Page
36	Buckley	Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) tables in the actual filings for each year during the period from 2006 through 2012.	1
37	Buckley	Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the projection filings for each year during the period from 2006 through 2012. If the amounts are different from the ones contained in the actual filings, please explain.	2

Brian Buckley
Manager, Compliance and Performance

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

37. Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) table in the projection filings for each year during the period from 2006 through 2012. If the amounts are different from the ones contained in the actual filings, please explain.

A. The maximum reward/(penalty) amounts are different from the ones contained in the actual filings because the projection filings contain estimated common equity and jurisdictional sales. The requested information is provided in the following table.

GPIF Maximum Performance Values
Projection Filings

	Fuel Savings/(Loss) ($000)	GPIF Reward/(Penalty) ($000)
2006	47,305	5,803
2007	58,302	5,830
2008	49,686	6,165
2009	60,487	8,123
2010	33,641	7,727
2011	28,354	7,711
2012	29,724	7,983

130001 Hearing Exhibits - 00627

Interrogatory Nos. 36-37 are in regard to the Generation Performance Incentive Factor (GPIF) program. Where appropriate, please provide data in a computerized spreadsheet format such as Excel.

36. Please provide the reward (penalty) and savings (loss) at maximum performance level contained in the reward (penalty) tables in the actual filings for each year during the period from 2006 through 2012.

A. The requested information is provided in the following table.

GPIF Maximum Performance Values
Actual True-up Filings

	Fuel Savings/(Loss) ($000)	GPIF Reward/(Penalty) ($000)
2006	47,305	5,501
2007	58,302	5,732
2008	49,686	6,561
2009	60,487	7,366
2010	33,641	7,547
2011	28,354	7,671
2012	29,724	7,781

130001 Hearing Exhibits - 00628

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fifth Set of Interrogatories, (No. 36-37) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 24th day of May, 2013.

Penelope Rusk

Sworn to and subscribed before me this 24th day of May, 2013.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission EE052251
Expires 03/01/2015

My Commission expires _____

88

TECO's Responses to Staff's Sixth Set of Interrogatories (Nos. 38-45)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 88
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0630-0642]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: AUGUST 9, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SIXTH SET OF INTERROGATORIES (NO. 38-45)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 38-45) propounded and served on July 10, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S SIXTH SET OF INTERROGATORIES (NO. 36-37)

Number	Witness	Subject	Bates Stamped Page
38	Buckley	Describe the manner in which FPL applied the formulaic representation at Original Sheet No. 3.400 where a provision limits the maximum allowed incentive dollars. As part of the response, please describe whether FPL's application of this provision, if any, has been changed by Commission orders since the inception of the GPIF, including the stipulation by Order No. 18136 in Docket No. 870001-EI.	1
39	Buckley	Have the maximum allowed incentive dollars ever exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of your company's GPIF projection or actual filings in the period of 2005 through 2012? If so, please provide the year and the reasons.	2
40	Buckley	Describe whether the linear scale and interpolation used by FPL in its reward (penalty) tables is based on data supporting the linear relationship or the need for simplicity. If applicable, please provide data that demonstrate the relationship between the performance levels and fuel savings.	3
41	Buckley	Based on the use of linear interpolation, should the reward (penalty) be capped at 50 percent of the fuel savings corresponding to the actual performance level in the reward (penalty) table by setting the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings? If not, please explain.	4
42	Buckley	Should the existing minimum heat rate threshold of 75 Btu/kWh be modified, with a different number or a percentage based on the unit efficiency? As part of the response, please provide the data and analysis supporting your response.	5
43	Buckley	Should there be a similar minimum availability performance threshold for the GPIF reward (penalty)? As part of the response, please provide the data and analysis supporting your response.	6

44	Buckley	Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? As part of the response, please provide the data and analysis supporting your response.	7
45	Buckley	Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? If so, provide data and analysis supporting such modification.	8

Brian Buckley
Manager, Compliance and Performance

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

Regarding the Generation Performance Incentive Factor (GPIF) program, please refer to the formulaic representation for the maximum allowed incentive dollars at Original Sheet No. 3.400, the GPIF reward (penalty) table (estimated) at Original Sheet No. 3.503, and the GPIF reward (penalty) table (actual) at Original Sheet No. 3.515 of the GPIF manual for Interrogatory Nos. 38-45.

38. Describe the manner in which TECO applied the formulaic representation at Original Sheet No. 3.400 where a provision limits the maximum allowed incentive dollars. As part of the response, please describe whether TECO's application of this provision, if any, has been changed by Commission orders since the inception of the GPIF, including the stipulation by Order No. 18136 in Docket No. 870001-EI.

A. Tampa Electric applies the formulaic representation in Original Sheet No. 3.400 consistently, but with two changes that reflect changing circumstances since the GPIF manual Original Sheet No. 3.400 was written.

- The company applies the formulaic representation consistent with the current 12-month fuel factor, as opposed to the previously utilized process of calculating six-month fuel factors, and the Average Common Equity calculation utilizes a 13-month period average instead of the seven-month period average described in Original Sheet No. 3.400.

- Tampa Electric calculates the Revenue Expansion Factor according to the formula described in Order No. PSC-09-0283-FOF-EI, issued on April 30, 2009 in Docket No. 080317-EI.

39. Have the maximum allowed incentive dollars ever exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of your company's GPIF projection or actual filings in the period of 2005 through 2012? If so, please provide the year and the reasons.

A. No. During the period 2005 through 2012, the maximum allowed incentive dollars have never exceeded 50 percent of the maximum attainable fuel savings in the reward (penalty) tables of Tampa Electric's GPIF projection or actual filings.

130001 Hearing Exhibits - 00635

40. Describe whether the linear scale and interpolation used by TECO in its reward (penalty) tables is based on data supporting the linear relationship or the need for simplicity. If applicable, please provide data that demonstrate the relationship between the performance levels and fuel savings.

A. Tampa Electric uses linear scale and interpolation to calculate the GPIF reward (penalty) tables because this is a reasonable, commonly used method of calculating the reward (penalty) amounts that would apply at various fuel savings values, based on a single regression analysis that determines the maximum fuel savings amount. It is more straight-forward than running multiple regression analyses for different availability levels that could result in somewhat different fuel savings amounts, and the company has had no reason to believe a more complicated analysis would yield a material change in accuracy.

130001 Hearing Exhibits - 00636

41. Based on the use of linear interpolation, should the reward (penalty) be capped at 50 percent of the fuel savings corresponding to the actual performance level in the reward (penalty) table by setting the maximum allowed incentive dollars at 50 percent of the maximum attainable fuel savings? If not, please explain.

A. As stated in the company's response to Interrogatory No. 40, the use of linear interpolation in calculating the GPIF reward (penalty) amounts is a reasonable solution to reduce modeling complexity needed to estimate various availability states that would result in multiple levels of fuel savings. The company is also not opposed to simplifying the calculations by indexing the GPIF reward (penalty) tables to a maximum incentive dollar amount that is equal to 50 percent of estimated maximum attainable fuel savings.

130001 Hearing Exhibits - 00637

42. Should the existing minimum heat rate threshold of 75 Btu/kWh be modified, with a different number or a percentage based on the unit efficiency? As part of the response, please provide the data and analysis supporting your response.

A. No. The existing minimum heat rate threshold of 75 Btu/kWh does not need to be modified. It is a reasonable value to use as a threshold, and it is appropriate to maintain this type of threshold for heat rate due to inherent and unavoidable variation of input fuel heat content, which is unavoidable when purchasing from fuel suppliers and changes in ambient conditions. Maintaining a 75 Btu/kWh threshold allows neither a GPIF reward nor penalty to be triggered by parameters outside of the company's control due to input fuel heat content variations.

130001 Hearing Exhibits - 00638

43. Should there be a similar minimum availability performance threshold for the GPIF reward (penalty)? As part of the response, please provide the data and analysis supporting your response.

A. No. There is no need to implement a minimum availability performance threshold for GPIF. Unlike heat rate, there are no operating parameters for availability performance that would make a minimum threshold appropriate.

130001 Hearing Exhibits - 00639

44. Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? As part of the response, please provide the data and analysis supporting your response.

A. No. There is no need to modify the reward (penalty) cap of 50 percent of fuel savings or the existing heat rate minimum threshold. The existing heat rate threshold is discussed in Tampa Electric's response to Interrogatory No. 42. The maximum GPIF incentive cap of 50 percent of fuel savings is already established and ensures that customers benefit from the incentive at least as much as does the company. However, as previously stated in the company's response to Interrogatory No. 41, Tampa Electric is not opposed to the idea Staff has raised, whereby the Commission could change the GPIF reward (penalty) tables so that they are indexed to 50 percent of the maximum attainable fuel savings. In addition, the company invests hundreds of millions of dollars in availability and heat rate improvements. The existing incentive mechanism works well in this regard, to the benefit of customers and the company.

45. Should the reward (penalty) cap and minimum threshold be modified to improve the effectiveness of the GPIF? If so, provide data and analysis supporting such modification.

A. See the company's response to Interrogatory No. 44.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Paula Brown who deposed and said that she is a Manager Regulatory Coordination, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Sixth Set of Interrogatories, (Nos. 38-45) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 7th day of August, 2013.

Paula K. Brown

Sworn to and subscribed before me this 7th day of August, 2013.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires

89

TECO's Responses to Staff's Seventh Set of Interrogatories (Nos. 46-48)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 89
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0643-0651]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: September 17, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SEVENTH SET OF INTERROGATORIES (NO. 46-48)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 46-48) propounded and served on August 28, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S SEVENTH SET OF INTERROGATORIES (NO. 46-48)

Number	Witness	Subject	Bates Stamped Page
46	Rusk	According to Document 3 of Exhibit PAR-2, the projected costs of the Polk Unit One ignition oil conversion project, including depreciation and return are $9,553,668, for the period January-December, 2013. Please identify the cost components of this project and describe how the $9,553,668 was calculated. Include in your response why the Company believes these costs are reasonable and prudent.	1
47	Rusk	In Tampa Electric's Response to Staff's First Data Request from Docket No. 120153-EI, Item No. 10, the Polk Unit One ignition oil conversion project was estimated to cost $14,690,000. Please identify what the actual cost was, and discuss the variance between the estimated cost and the actual cost. Include in your response why the Company believes the actual costs are reasonable and prudent.	4
48	Rusk	In Tampa Electric's Response to Staff's First Data Request from Docket No. 120153-EI, Item No. 10, the Polk Unit One ignition oil conversion project was estimated to cost $14,690,000. Please identify what the actual cost was, and discuss the variance between the estimated cost and the actual cost. Include in your response why the Company believes the actual costs are reasonable and prudent.	5

Penelope Rusk
Administrator, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

For the purpose of these interrogatories, please refer to Document 3 of Exhibit PAR-2, attached to the testimony of Tampa Electric witness Penelope A. Rusk, filed on August 2, 2013, and also to Tampa Electric's Response to Staff's First Data Request from Docket No. 120153-EI.

46. According to Document 3 of Exhibit PAR-2, the projected costs of the Polk Unit One ignition oil conversion project, including depreciation and return are $9,553,668, for the period January-December, 2013. Please identify the cost components of this project and describe how the $9,553,668 was calculated. Include in your response why the Company believes these costs are reasonable and prudent.

A. Document No. 3 of Exhibit No. ___ (PAR-2) shows the projected costs of the Polk Unit 1 ignition oil conversion project, including depreciation and return are $2,356,259 for the period January through December 2013. The projected net benefits to ratepayers for this project are $9,553,668. The cost components are shown on Document No. 3 and are summarized in the table below.

Polk Unit 1 Ignition Oil Conversion
Projected Costs

	January – June 2013 (Actual)	July – December 2013 (Estimated)	Total January – December 2013
Depreciation	$ 0	$ 1,542,806	$ 1,542,806
Return	74,893	738,560	813,453
Total	$ 74,893	$ 2,281,366	$ 2,356,259

Depreciation cost is calculated based on five-year straight-line amortization rates. Return is calculated using the company's return on investment rate, per the FPSC-approved Weighted Average Cost of Capital Stipulation and Settlement Agreement dated July 17, 2012. The return calculation, showing the monthly rates used in Document No. 3, is attached.

Tampa Electric's requested recovery of $2,356,259 for 2013 project costs is reasonable and prudent since,

(1) The project is cost-effective and provides $9,553,668 in projected net benefits, due to fuel savings, to customers.

(2) The company has complied with Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI, on September 27, 2012, in which the Commission approved the project for recovery through the fuel clause.

Also see witness Rusk's testimony at 6:22 through 7:25, submitted in this docket on August 2, 2013.

Calculation of Revenue Requirement Rate of Return
for Cost Recovery Clauses
Per 2012 WACC Stipulation and Settlement Agreement
July to December 2013 Actual/Estimated Period

	(1) Jurisdictional Rate Base Actual May 2013 Capital Structure ($000)	(2) Ratio	(3) Cost Rate	(4) Weighted Cost Rate
		%	%	%
Long Term Debt	$ 1,425,239	37.00%	5.78%	2.14%
Short Term Debt	0	0.00%	0.66%	0.00%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	106,560	2.77%	2.91%	0.08%
Common Equity	1,647,409	42.77%	11.25%	4.81%
Deferred ITC - Weighted Cost	8,381	0.22%	8.71%	0.02%
Accumulated Deferred Income Taxes & Zero Cost ITCs	664,214	17.24%	0.00%	0.00%
Total	$ 3,851,803	100.00%		7.05%

ITC split between Debt and Equity:

Long Term Debt	$ 1,425,239	Long Term Debt	46.38%
Short Term Debt	0	Short Term Debt	0.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,647,409	Equity - Common	53.62%
Total	$ 3,072,648	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .01920% * 46.38%	0.0089%
Equity = .01920% * 53.62%	0.0103%
Weighted Cost	0.0192%

Total Equity Cost Rate:		**Monthly Rate:**
Preferred Stock	0.0000%	
Common Equity	4.8116%	
Deferred ITC - Weighted Cost	0.0103%	
	4.8219%	0.40183%
Times Tax Multiplier	1.628000	
Total Equity Component	7.8500%	

Total Debt Cost Rate:		**Monthly Rate:**
Long Term Debt	2.1386%	
Short Term Debt	0.0000%	
Customer Deposits	0.0806%	
Deferred ITC - Weighted Cost	0.0089%	
Total Debt Component	2.2281%	0.18568%
Total Weighted Cost:	10.0781%	

Notes:
Column (1) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012
Column (2) - Column (1) / Total Column (1)
Column (3) - From WACC Stipulation & Settlement Agreement Dated July 17, 2012
Column (4) - Column (2) x Column (3)

47. In Tampa Electric's Response to Staff's First Data Request from Docket No. 120153-EI, Item No. 10, the Polk Unit One ignition oil conversion project was estimated to cost $14,690,000. Please identify what the actual cost was, and discuss the variance between the estimated cost and the actual cost. Include in your response why the Company believes the actual costs are reasonable and prudent.

A. With essentially all costs accounted for, Tampa Electric expects the final cost of the Polk Unit 1 ignition oil conversion project to be $16,196,000, or $1,506,000 more than projected. The company's original estimate included in the Docket No. 120153-EI filing was a preliminary engineering estimate. When the detailed engineering estimate was completed, there was a change which required re-engineering and additional steam blending costs. The items that make up the $1.5 million change are listed in the following table.

Polk Unit 1 Ignition Oil Conversion Project
Reasons for Cost Change

GE start-up support: software issues	$504,000
Change in steam blending location	252,000
Electrical support under-estimated	241,000
HRSG drain piping and platforms, additional scope	171,000
Gas conditioning skid and auxiliary boiler vendor support and materials	156,000
Engineering and support under-estimated	129,000
Misc.: higher construction, piping, valves; lower permitting and oil system demo	53,000
Total Cost Change	$1,506,000

Despite the increase of $1.5 million over the preliminary engineering cost estimate, the Polk Unit 1 ignition oil conversion project was completed in a prudent and reasonable manner, and it will provide long-term benefits of significant fuel savings to customers. In addition, customers are protected because if in any year during the five-year cost recovery period, the annual fuel savings do not exceed the annual amortized project costs, the company's cost recovery through the fuel clause is limited to actual fuel savings, in accordance with Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI, on September 27, 2012.

48. According to Document 3 of Exhibit PAR-2, the projected fuel savings from this conversion are $11,909,927 for the period January-December, 2013. Please identify the forecasting assumptions the Company made in calculating the fuel savings.

A. Tampa Electric estimated 2013 fuel savings as a result of the Polk Unit 1 ignition oil conversion based on the differential between expected light oil and natural gas fuel prices and the amount of generation expected while Polk CT 1 operates on natural gas (instead of light oil). The assumptions are listed below.

The company did not attempt to forecast the number of starts or auxiliary boiler usage for Polk Unit 1, although these items contribute to fuel savings on an actual basis. The reasons that these two items were not included in the actual/estimated projection are (1) they are quite variable from month to month, and (2) they produce small amounts of fuel savings in relation to the project's total fuel savings. For example, in June 2013, of the total actual $5,993,236 fuel savings, only $59,301 was due to number of starts and $121,767 was related to auxiliary boiler operations; together, these amounts represent only 3.0 percent of total fuel savings. While these items do provide additional fuel savings benefits to customers, on top of the amount that has been projected, they are negligible, and the actual fuel savings amounts are calculated and included in the company's true-up schedule.

Assumptions

	Jan – Jun 2013 (Actual)	Jul – Dec 2013 (Estimated)
Light Oil ($/kWh)	$ 0.33320	$ 0.33320
Natural Gas ($/kWh)	$ 0.03526	$ 0.05310
Projected kWh Polk CT1 operated on NG	19,508,000	21,110,000

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Seventh Set of Interrogatories, (No. 46-48) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 13th day of September, 2013.

Penelope Rusk

Sworn to and subscribed before me this 13th day of September, 2013.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

90

TECO's Responses to Staff's Eighth Set of Interrogatories (No. 49)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. _____ EXHIBIT 90
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 0652-0657]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: September 23, 2013

TAMPA ELECTRIC COMPANY'S

ANSWERS TO EIGHTH SET OF INTERROGATORIES (NO. 49)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 49) propounded and served on September 3, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S EIGHTH SET OF INTERROGATORIES (NO. 49)

Number	Witness	Subject	Bates Stamped Page
49	Rusk	Please recalculate the estimated fuel savings listed in Exhibit PAR-2 (Document No. 3 at line 31) based on mmbtu instead of kWh. Please provide a revised Computation of Savings table reflecting the requested recalculation.	1

Penelope Rusk
Administrator, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

49. Please recalculate the estimated fuel savings listed in Exhibit PAR-2 (Document No. 3 at line 31) based on mmbtu instead of kWh. Please provide a revised Computation of Savings table reflecting the requested recalculation.

A. The appropriate method of calculating fuel savings is on a kWh basis, as provided in Exhibit No. ___ (PAR-2). The calculation of fuel savings on a mmBtu basis does not reflect the fuel savings of the more beneficial heat rate achieved by converting the Polk Unit 1 equipment to run on natural gas instead of light oil. Despite the aforementioned issue with the requested calculation, Tampa Electric performed the calculation for the estimated period, and it is provided on the attached pages.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S EIGHTH SET OF
INTERROGATORIES
INTERROGATORY NO.49
PAGE 2 OF 2
FILED: SEPTEMBER 23, 2013

POLK 1 CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JULY, 2013 THROUGH DECEMBER, 2013

		JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062	$ 15,428,062
2	ADD INVESTMENT	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-
4	ENDING BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062
5								
6								
7	AVERAGE BALANCE	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	15,428,062	
8	DEPRECIATION RATE	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	1.666667%	
9	DEPRECIATION EXPENSE	257,134	257,134	257,134	257,134	257,134	257,134	1,542,806
10	LESS RETIREMENTS	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	-	257,134	514,269	771,403	1,028,537	1,285,672	-
12	ENDING BALANCE DEPRECIATION	257,134	514,269	771,403	1,028,537	1,285,672	1,542,806	1,542,806
13								
14								
15	ENDING NET INVESTMENT	15,170,927	14,913,793	14,656,659	14,399,524	14,142,390	13,885,256	13,885,256
16								
17								
18	AVERAGE INVESTMENT	$ 15,299,494	$ 15,042,360	$ 14,785,226	$ 14,528,091	$ 14,270,957	$ 14,013,823	
19	ALLOWED EQUITY RETURN	.40183%	.40183%	.40183%	.40183%	.40183%	.40183%	
20	EQUITY COMPONENT AFTER-TAX	61,477	60,444	59,411	58,378	57,344	56,311	353,365
21	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
22	EQUITY COMPONENT PRE-TAX	100,085	98,403	96,721	95,039	93,356	91,674	575,278
23								
24	ALLOWED DEBT RETURN	.18568%	.18568%	.18568%	.18568%	.18568%	.18568%	
25	DEBT COMPONENT	28,407	27,930	27,452	26,975	26,498	26,020	163,282
26								
27	TOTAL RETURN REQUIREMENTS	128,492	126,333	124,173	122,014	119,854	117,694	738,560
28								
29	TOTAL DEPRECIATION & RETURN	385,626	383,467	381,307	379,148	376,988	374,828	2,281,366
30								
31	ESTIMATED FUEL SAVINGS	$398,848	$407,015	$354,682	$682,148	$259,202	$341,449	$2,443,346
32	TOTAL DEPRECIATION & RETURN	$385,626	$383,467	$381,307	$379,148	$376,988	$374,828	$2,281,366
33	NET BENEFIT (COST) TO RATEPAYER	$13,222	$23,548	($26,625)	$303,000	($117,786)	($33,379)	$161,980
34								

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 10.08% (EQUITY 7.8501% , DEBT 2.2281%).
THE RATES ARE FROM THE MAY 2013 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012)
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%

130001 Hearing Exhibits - 00656

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Eighth Set of Interrogatories, (No. 49) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 20th day of September, 2013.

Penelope Rusk

Sworn to and subscribed before me this 20th day of September, 2013.

Denise Chichetto

Notary Public State of Florida
Denise Chichetto
My Commission EE 181752
Expires 03/21/2016

My Commission expires _____

91

TECO's Responses to Staff's Ninth Set of Interrogatories (Nos. 50-61)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 91
PARTY Florida Public Service Commission Staff
DESCRIPTION (Redacted only)
[Bates Nos. 0658-0689]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 130001-EI FILED: OCTOBER 17, 2013

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO NINTH SET OF INTERROGATORIES (NO. 50-61)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 50-61) propounded and served on September 27, 2013, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
INDEX TO STAFF'S NINTH SET OF INTERROGATORIES (NOS. 50-61)

Number	Witness	Subject	Bates Stamped Page
50	Caldwell	For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for natural gas, please provide the following information in a schedule format: (a) the transaction date (the date the swap was entered into) for the swap; (b) the fixed price for the swap; (c) the month or period in the future the swap is covering; and (d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.	1
51	Caldwell	For interrogatory 50 above, please explain any difference between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.	7
52	Caldwell	For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013 associated with options for natural gas prices, please provide the following information in a schedule format: (a) the transaction date for the option; (b) the option price or premium; (c) the type of option; (d) the time to expiration; and (e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.	8
53	Caldwell	For interrogatory 52 above, please explain any difference between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.	9
54	Caldwell	Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2012, and ending July 31, 2013.	10

55	Caldwell	For the twelve months beginning August 1, 2012, and ending July 31, 2013, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in TECO's risk management plan or otherwise stated in internal procedures governing TECO's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.	11
56	Caldwell	Please provide a comparison of TECO's Risk Management Plans for 2013 and 2014. Please describe any changes between these respective plans.	12
57	Caldwell	Regarding hedging activities, how does TECO assess and evaluate counter-party credit risk?	23
58	Caldwell	For open hedging transactions since August 1, 2012, has TECO experienced any defaults by a counter-party? If so, please identify the counter-party and explain.	24
59	Caldwell	For all currently open hedging transactions, does TECO have any concern regarding default by a counter-party for any specific transaction? If so, please identify the counter-party and explain.	25
60	Caldwell	Since January 1, 2012, has TECO stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If so, please identify the counter-party and explain.	26
61	Caldwell	Has TECO incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If so, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.	27

Brent Caldwell
Director, Bulk Fuel & Power

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

50. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013, associated with swap contracts for natural gas, please provide the following information in a schedule format:

(a) the transaction date (the date the swap was entered into) for the swap;
(b) the fixed price for the swap;
(c) the month or period in the future the swap is covering; and
(d) the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

A. The requested information is provided in the following table.

REDACTED

Transaction Date (a)	Month of Swap (b)	Fixed Price (c)	NYMEX Forward Price (d)
14-Oct-10	201208	[redacted]	$ 4.998
14-Oct-10	201208		$ 4.998
14-Oct-10	201208		$ 4.998
25-Aug-10	201208		$ 5.136
25-Aug-10	201208		$ 5.136
4-May-12	201208		$ 2.495
4-May-12	201208		$ 2.495
17-Feb-11	201208		$ 4.664
17-Feb-11	201208		$ 4.664
23-Aug-11	201208		$ 4.435
23-Aug-11	201208		$ 4.435
23-Aug-11	201208		$ 4.435
25-Aug-11	201208		$ 4.412
25-Aug-11	201208		$ 4.412
26-Aug-11	201208		$ 4.450
26-Aug-11	201208		$ 4.450
14-Oct-10	201209		$ 5.020
14-Oct-10	201209		$ 5.020
14-Oct-10	201209		$ 5.020
27-Sep-10	201209		$ 4.933
6-May-11	201209		$ 4.840
27-Sep-10	201209		$ 4.933
11-May-11	201209		$ 4.814
11-May-11	201209		$ 4.814
25-Aug-11	201209		$ 4.417
26-Aug-11	201209		$ 4.455
26-Aug-11	201209		$ 4.455
12-Sep-11	201209		$ 4.411
6-Oct-11	201209		$ 4.204
6-Oct-11	201209		$ 4.204
6-Oct-11	201209		$ 4.204
17-Apr-12	201209		$ 2.297
17-Apr-12	201209		$ 2.297
6-May-11	201210		$ 4.893
26-Oct-10	201210		$ 4.979
26-Oct-10	201210		$ 4.979
28-Jan-11	201210		$ 4.924
27-Apr-11	201210		$ 5.028
11-May-11	201210		$ 4.867
11-May-11	201210		$ 4.867
25-Aug-11	201210		$ 4.444
26-Aug-11	201210		$ 4.482
26-Aug-11	201210		$ 4.482
6-Oct-11	201210		$ 4.238
6-Oct-11	201210		$ 4.238
25-Jan-12	201210		$ 3.162

REDACTED

Transaction Date (a)	Month of Swap (b)	Fixed Price (c)	NYMEX Forward Price (d)
13-Jul-12	201210		$ 2.894
13-Jul-12	201210		$ 2.894
10-Feb-11	201211		$ 4.966
6-May-11	201211		$ 5.049
22-Nov-10	201211		$ 5.309
11-May-11	201211		$ 5.027
22-Aug-11	201211		$ 4.603
26-Aug-11	201211		$ 4.646
7-Aug-12	201211		$ 3.150
9-Aug-12	201211		$ 3.156
9-Aug-12	201211		$ 3.156
21-Jun-12	201212		$ 3.244
6-May-11	201212		$ 5.271
9-Dec-10	201212		$ 5.397
11-Feb-11	201212		$ 5.154
11-May-11	201212		$ 5.254
23-Aug-11	201212		$ 4.885
23-Aug-11	201212		$ 4.885
23-Aug-11	201212		$ 4.885
25-Jun-12	201212		$ 3.303
7-Sep-12	201212		$ 3.079
13-Sep-12	201212		$ 3.385
13-Sep-12	201212		$ 3.385
6-Nov-12	201212		$ 3.617
27-Nov-12	201212		$ 3.769
27-Nov-12	201212		$ 3.769
25-Oct-12	201301		$ 3.910
9-Nov-12	201301		$ 3.634
27-Jan-11	201301		$ 5.411
6-May-11	201301		$ 5.403
11-May-11	201301		$ 5.383
26-Jan-12	201301		$ 3.606
17-Feb-12	201301		$ 3.743
23-Apr-12	201301		$ 3.112
13-Jul-12	201301		$ 3.546
13-Jul-12	201301		$ 3.546
11-Sep-12	201301		$ 3.450
11-Sep-12	201301		$ 3.450
6-Nov-12	201301		$ 3.748
4-May-12	201302		$ 3.395
9-Nov-12	201302		$ 3.647
9-Nov-12	201302		$ 3.647
28-Feb-11	201302		$ 5.346
9-May-11	201302		$ 5.313
22-Aug-11	201302		$ 4.969
7-Feb-12	201302		$ 3.599

REDACTED

Transaction Date (a)	Month of Swap (b)	Fixed Price (c)	NYMEX Forward Price (d)
17-Feb-12	201302		$ 3.752
22-Feb-12	201302		$ 3.763
21-Mar-12	201302		$ 3.493
7-Aug-12	201302		$ 3.551
9-Aug-12	201302		$ 3.570
11-Sep-12	201302		$ 3.472
6-Nov-12	201302		$ 3.754
6-Nov-12	201302		$ 3.754
7-Nov-12	201302		$ 3.720
21-Jun-12	201303		$ 3.374
21-Jun-12	201303		$ 3.374
14-Dec-12	201303		$ 3.380
28-Mar-11	201303		$ 5.441
27-Sep-11	201303		$ 4.874
9-Nov-12	201303		$ 3.622
9-May-11	201303		$ 5.241
22-Feb-12	201303		$ 3.747
20-Mar-12	201303		$ 3.465
25-Jun-12	201303		$ 3.436
7-Sep-12	201303		$ 3.245
7-Sep-12	201303		$ 3.245
6-Nov-12	201303		$ 3.729
13-Dec-12	201303		$ 3.407
3-Jan-13	201303		$ 3.214
25-Oct-12	201304		$ 3.857
25-Oct-12	201304		$ 3.857
9-Nov-12	201304		$ 3.611
27-Apr-11	201304		$ 5.183
9-May-11	201304		$ 5.026
28-Oct-11	201304		$ 4.541
22-Feb-12	201304		$ 3.708
21-Mar-12	201304		$ 3.439
17-Apr-12	201304		$ 3.149
23-Apr-12	201304		$ 3.082
13-Jul-12	201304		$ 3.514
13-Jul-12	201304		$ 3.514
11-Sep-12	201304		$ 3.459
6-Nov-12	201304		$ 3.710
3-Jan-13	201304		$ 3.250
4-Jan-13	201304		$ 3.337
4-Jan-13	201304		$ 3.337
14-Jan-13	201304		$ 3.412
19-Mar-13	201304		$ 3.969
6-May-11	201305		$ 5.090
28-Nov-11	201305		$ 4.247
4-May-12	201305		$ 3.404

REDACTED

Transaction Date (a)	Month of Swap (b)	Fixed Price (c)	NYMEX Forward Price (d)
9-Nov-12	201305		$ 3.650
9-May-11	201305		$ 5.040
17-Feb-12	201305		$ 3.727
12-Mar-12	201305		$ 3.357
21-Mar-12	201305		$ 3.478
7-Aug-12	201305		$ 3.536
9-Aug-12	201305		$ 3.569
6-Sep-12	201305		$ 3.344
16-Oct-12	201305		$ 3.852
6-Nov-12	201305		$ 3.744
4-Jan-13	201305		$ 3.393
4-Jan-13	201305		$ 3.393
3-Jan-13	201305		$ 3.306
14-Jan-13	201305		$ 3.464
21-Jun-12	201306		$ 3.412
5-Dec-11	201306		$ 4.266
27-Dec-11	201306		$ 3.976
9-Nov-12	201306		$ 3.693
27-Jun-11	201306		$ 4.915
31-Oct-11	201306		$ 4.601
17-Feb-12	201306		$ 3.772
12-Mar-12	201306		$ 3.411
21-Mar-12	201306		$ 3.530
25-Jun-12	201306		$ 3.475
6-Sep-12	201306		$ 3.390
7-Sep-12	201306		$ 3.336
11-Sep-12	201306		$ 3.546
16-Oct-12	201306		$ 3.891
6-Nov-12	201306		$ 3.784
13-Dec-12	201306		$ 3.521
4-Jan-13	201306		$ 3.448
4-Jan-13	201306		$ 3.448
3-Jan-13	201306		$ 3.363
14-Jan-13	201306		$ 3.519
9-Nov-12	201307		$ 3.735
26-Jul-11	201307		$ 5.028
26-Jul-11	201307		$ 5.028
27-Jul-11	201307		$ 5.026
25-Jan-12	201307		$ 3.730
26-Jan-12	201307		$ 3.629
17-Feb-12	201307		$ 3.815
12-Mar-12	201307		$ 3.454
21-Mar-12	201307		$ 3.576
13-Jul-12	201307		$ 3.620
6-Sep-12	201307		$ 3.435
11-Sep-12	201307		$ 3.587

REDACTED

Transaction Date (a)	Month of Swap (b)	Fixed Price (c)	NYMEX Forward Price (d)
11-Sep-12	201307	[redacted]	$ 3.587
13-Sep-12	201307		$ 3.638
16-Oct-12	201307		$ 3.933
6-Nov-12	201307		$ 3.827
3-Jan-13	201307		$ 3.421
14-Jan-13	201307		$ 3.574
14-Jan-13	201307		$ 3.574
19-Mar-13	201307		$ 4.074

51. For interrogatory 50 above, please explain any difference between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

A. Tampa Electric did not execute any transactions for the months of August 2012 through July 2013 where the fixed price of the swap varied by more than five percent from the corresponding futures or forward price.

52. For realized (actual) hedging gains and losses for the twelve months beginning August 1, 2012, and ending July 31, 2013 associated with options for natural gas prices, please provide the following information in a schedule format:
(a) the transaction date for the option;
(b) the option price or premium;
(c) the type of option;
(d) the time to expiration; and
(e) the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

A. Tampa Electric did not execute any financial options for natural gas price hedging for the time period August 1, 2012 through July 31, 2013.

53. For interrogatory 52 above, please explain any difference between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

A. Tampa Electric did not execute any financial options for natural gas price hedging for the time period August 1, 2012 through July 31, 2013.

54. Please state the realized hedging gains and losses by fuel type and by type of hedging instrument for the twelve months beginning August 1, 2012, and ending July 31, 2013.

A. The requested information is provided in the following table.

	Type of Hedge	Mark-to-Market Saving/(Loss)
Aug-12	Swaps	$ (5,495,850)
Sep-12	Swaps	$ (6,371,570)
Oct-12	Swaps	$ (4,050,300)
Nov-12	Swaps	$ (1,744,670)
Dec-12	Swaps	$ (1,496,760)
Jan-13	Swaps	$ (1,482,130)
Feb-13	Swaps	$ (1,744,150)
Mar-13	Swaps	$ (828,170)
Apr-13	Swaps	$ 1,127,945
May-13	Swaps	$ 1,794,365
Jun-13	Swaps	$ 1,902,130
Jul-13	Swaps	$ (190,245)
Total		**$ (18,579,405)**

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 130001-EI
STAFF'S NINTH SET OF
INTERROGATORIES
INTERROGATORY NO. 55
PAGE 1 OF 1
FILED: OCTOBER 17, 2013

55. For the twelve months beginning August 1, 2012, and ending July 31, 2013, for each month that hedged volumes of fuel oil or natural gas were outside the percentage range for volumes to be hedged stated in TECO's risk management plan or otherwise stated in internal procedures governing TECO's hedging activities, please state the month, the extent to which the volume hedged was outside of the range, and an explanation of the cause.

A. The requested information regarding natural gas hedges is provided in the following table. Tampa Electric did not hedge fuel oil during this period.

Tampa Electric
Summary of Natural Gas Hedge Volumes Relative to Actual Consumption
August 2012 - July 2013

Month-Year	Target Minimum	Target Maximum	% of Actual Consumption Hedged	Above Maximum? Below Minimum?	Explanation
Aug-12	60%	80%	[redacted]	No	
Sep-12	60%	80%		No	
Oct-12	60%	80%		No	
Nov-12	60%	80%		No	
Dec-12	60%	80%		Yes	Gas-fired generation lower than projected due to lower retail sales.
Jan-13	60%	80%		Yes	Gas-fired generation higher than projected due to lower than projected coal-fired generation.
Feb-13	60%	80%		Yes	Gas-fired generation higher than projected due to lower than projected coal-fired generation.
Mar-13	60%	80%		No	
Apr-13	60%	80%		No	
May-13	60%	80%		No	
Jun-13	60%	80%		No	
Jul-13	60%	80%		Yes	Gas-fired generation lower than projected due to lower retail sales and higher coal-fired generation.
12-Month Cumulative	60%	80%	68%	No	Cumulative hedge percentage is close to middle of the desired hedge range.

130001 Hearing Exhibits - 00672

56. Please provide a comparison of TECO's Risk Management Plans for 2013 and 2014. Please describe any changes between these respective plans.

A. All changes in Tampa Electric's 2014 Risk Management Plan compared to 2013 are changes to the time period or actual data associated with the different time period. There are no changes to the structure or approach to the Risk Management Plan in 2014 compared to 2013.

The requested comparison is attached.

TAMPA ELECTRIC COMPANY
FUEL PROCUREMENT AND WHOLESALE POWER PURCHASES
RISK MANAGEMENT PLAN
~~2013~~
2014

Introduction

Tampa Electric serves its retail customers' electricity needs through a portfolio of generation and wholesale purchases. Tampa Electric's generation fuel mix is primarily a blend of coal and natural gas. While fuel mix diversity enhances long-term reliability, the reliance on natural gas can potentially increase variation in fuel prices. The company's risk management activities reduce the impact of price uncertainty and volatility to the Fuel and Purchased Power Cost Recovery Clause.

I. Qualitative and Quantitative Risk Management Objectives

A. Qualitative objectives

Tampa Electric's goals in managing risks associated with fuel or power purchases are focused on minimizing supply risk to ensure reliability of electric service to its customers at a reasonable price. To the extent price risk can be reduced without compromising supply reliability or imposing unnecessary costs on customers, Tampa Electric is committed to executing strategies to accomplish its risk management goals.

B. Quantitative objectives

Tampa Electric's quantitative objective is to prudently manage its fuel and wholesale energy procurement activities to minimize the variance from projected expenditures while taking advantage of cost-saving opportunities that do not result in increased supply risk. Tampa Electric has established a portfolio of fuel and purchased power products with creditworthy counterparties for known volumes and prices.

II. Oversight & Reporting of Fuel Procurement Activities

The company provides fuel and wholesale energy procurement activities with independent and unavoidable oversight.

A. The TECO Energy Board of Directors established an Energy Risk Management Policy ("Risk Policy"). This policy governs all energy

commodities transacting activities at each of TECO Energy's operating units. The scope of this policy includes:

- Roles and responsibilities of various persons and functions with respect to risk management
- Authorized transacting activity
- Risk limits
- Valuation and data management
- Credit risk management
- Reporting
- Compliance and enforcement

B. The Risk Policy established the Risk Advisory Committee ("RAC"). The responsibilities of the RAC include the following activities:

- Reviewing the Risk Management Policy periodically and recommending changes and enhancements for approval by the Board of Directors ("Board").
- Reviewing corporate risk limits for recommendation to the Board.
- Establishing the quantitative limits for operating companies within Board approved corporate risk limits. The RAC may, at its discretion, delegate approval of sub-limits to operating company management.
- Approving parameters for counterparty credit limits and the allocation of limits among the operating companies.
- Establishing guidelines for risk management and measurement.
- Overseeing and reviewing the risk management process and infrastructure.
- Reviewing and approving transacting strategies proposed by the operating companies.
- Understanding and approving methodologies used for valuation and risk measurement.
- Reviewing and approving corporate and operating company risk limits.
- Establishing credit underwriting standards, and monitoring credit risk-taking activities and related exposures.
- Reviewing risk reports, including portfolio risk summaries and profitability and performance summaries.
- Enacting, maintaining, and enforcing limit violation and trader misconduct policies.
- Taking appropriate courses of action when the risk position of a transacting group has exceeded or is approaching the established limits.
- Reviewing and approving new risk management products.
- Presenting periodic reports to the Board or its committees.

C. TECO Energy established a corporate risk management function ("middle office"), which is overseen by the Director of Independent Risk Oversight.

D. Tampa Electric established additional oversight or control mechanisms to ensure compliance with policies and procedures. The following practices provide checks and balances on fuel and purchased power procurement activities.
- Fuel and wholesale energy procurement activities are conducted in accordance with company guidelines, including review by the operating stations and other management.
- All agreements are formalized in a written contract that is reviewed by legal counsel.
- The contracts are reviewed by the Director, Independent Risk Oversight of TECO Energy's Energy Risk Management Department for potential credit risks and incorporation of appropriate credit protection.
- The company maintains approval authority restrictions based on term and value of the transaction.
- Payments of invoices under each contract are settled and approved by an independent department.
- Each transaction is eligible for review by outside, internal and regulatory auditors.
- Information systems provide transaction authority control, credit monitoring, mark-to-market and value-at-risk analysis and other key controls.

E. In accordance with the Risk Policy, Tampa Electric established commodity specific transaction limits for commodity transactions.
- The Risk Authorizing Committee reviews and approves commodity transaction limits on an individual basis.
- The limits include commodity, physical or financial, tenor (time limit), and dollar amount.
- Only a few individuals are authorized to execute financial hedging transactions.

F. Tampa Electric's Fuels Management Department has updated and formalized its policies and procedures. The key elements of its policies and procedures are:
- Financial hedging of fuel commodities are for mitigation of risk to fuel price uncertainty and volatility.
- Hedging will be conducted in a manner consistent with the Risk Management Plan approved by the RAC.
- Execution of hedges under the Risk Management Plan will be consistent with approved transaction limits for authorized transactors.
- Duties will be separated to assure sufficient control over hedging transactions.
- Hedging activity will be monitored regularly and reported at least once a month to insure consistency with the Risk Management Plan.

G. Reports are generated that summarize the fuel procurement activities of the company. These include monthly financial reports produced by Regulatory Accounting, FERC Electric Quarterly Reports, FERC Form 1, FERC Form 580, FERC Form 923, FERC Form 552, FPSC Form 423, FPSC A schedules and FPSC E schedules. In addition, position and mark-to-market reports are produced and reviewed by the Director of Independent Risk Oversight. The appropriate entries and related disclosures are made in the company's books and records as required by accounting standards.

III. Risk Assessment

In its Risk Policy, TECO Energy has identified the following types of risks for its commodity portfolio.

A. Market Risk

Market risk is the potential change in value of a commodity contract caused by adverse changes in market factors (price and volatility). The following are types of market risk.

1. **Price Risk:** Price risk refers to the uncertainty associated with changes in the price of an underlying asset. For instance, if a company has a short position in the market (e.g., needs to meet load requirements by purchasing electricity or natural gas), it will be susceptible to price increases. Conversely, if a company is in a long position (e.g., excess generation or natural gas supply), it is exposed to decreases in market prices. Tampa Electric manages its price risk using physical and financial hedges.

   In ~~2013~~2014, Tampa Electric is subject to limited price risk related to variation in coal prices. That price risk is mitigated in part because the company has already contracted for much of its expected coal needs at known prices. Expected market conditions do not currently require further price risk mitigation, for the reasons described in Section IV of this plan.

   Tampa Electric evaluated its exposure to changes in the price for natural gas during ~~2013~~2014 based on the forward price and estimated uncertainty in the price of natural gas and the company's expected usage under both low and high price natural gas cases. Natural gas expenditures decrease in the low case by an estimated $~~65.1~~40.0 million and total fuel and purchased power costs decrease by $~~70.7~~68.5 million due to lower prices. In the high case, natural gas expenditures increase by an estimated $~~67.7~~75.2 million, and the total fuel and purchased power costs increase by

$~~72.7~~52.6 million. This exposure estimate does not take into account any hedges the company may implement to limit its exposure. Tampa Electric's hedging strategy with respect to natural gas and purchased power is outlined in Section IV of this plan.

Tampa Electric requires small quantities of fuel oil and maintains a contract that eliminates its supply risk. Due to the small quantities of fuel oil needed for generation, the cost impact caused by price risk is minimal and is therefore not quantified.

2. **Time Spread Risk:** This is the risk that the relationship between two points (i.e., one month versus six months) on the forward curve changes. Because the shape of the fuel or electricity forward curve changes to reflect the market's expectations of spot and future fuel or electricity prices, the relationship between any two points on the curve is not always constant. Because of the nature of its business Tampa Electric has little reason or opportunity to offset energy commodity requirements in one month with resources delivered in another month. Therefore, time spread risk is not a significant issue for Tampa Electric.

3. **Liquidity Risk:** Liquidity risk is associated with the lack of marketability of a commodity. It includes the risk of an adverse cost or return variation stemming from the lack of marketability of a financial instrument. Liquidity risk may arise because a given position is very large relative to typical trading volumes of like commodity and contract tenor, or because market conditions are unsettled. Liquidity risk is usually reflected in a wide bid-ask spread and large price movements in response to any attempt to buy or sell. A firm facing the need to quickly unwind a portfolio of illiquid instruments may find it necessary to sell at prices far below fair value. Tampa Electric is not exposed to liquidity risk for natural gas financial instruments since the company does not purchase instruments for resale. Tampa Electric does have some liquidity risk for wholesale power transactions since the Florida market has a limited number of participants.

4. **Basis Risk:** Basis risk is the risk exposure due to a difference in commodity value between different delivery points. Electricity markets are regional. Prices can be different at different locations because of differences in both supply costs and the cost of transmission between the two locations. These price differences are dynamic, primarily due to changes in transmission availability between the two locations. Due to the stability of the coal market, Tampa Electric's negligible use of oil, and the indexing of its natural

gas contract pricing, basis risk is not a significant issue for the company.

Fundamentally, market risk is created by the existence of "open" positions. An open position is the difference between an existing requirement and the ability to meet that requirement with existing resources.

B. Volume Risk

Volume risk is the potential adverse economic impact of unanticipated changes in supply or demand. Tampa Electric faces supply risk, because there is uncertainty associated with the availability of generating units or fuel availability for those units. If a generating unit fails, Tampa Electric must replace the power with another unit's generation or with purchased power at market prices. Tampa Electric also faces demand risk since there is uncertainty associated with customer demand, and thus uncertainty in the determination of the fuel or energy purchase volumes necessary to supply such demand. Tampa Electric's volume risk for fuel and purchased power in ~~2013~~2014 will be managed operationally and through contract terms enforcement, including appropriate legal remedies, should a party default.

C. Credit Risk

Credit risk is the risk of financial loss due to a counterparty's failure to fulfill the terms of a contract on a timely basis. It includes both settlement risk associated with payment for fuel or energy received, as well as the potential risk that the counterparty defaults on an obligation to provide or receive fuel or energy. Credit risk depends on the probability of counterparty default, the concentration of credit exposure with a small number of counterparties, the total amount of exposure, and the volatility of markets. Tampa Electric's credit risk will vary based on the number of its trading counterparties and the mark-to-market value of its hedge transactions. Tampa Electric's existing credit risk is minimal since it uses a wide variety of counterparties, and has systems and processes in place to monitor and control credit risk.

D. Administrative Risk

Administrative risk is risk of loss associated with deficiencies in a company's internal control structure and management reporting due to human error, fraud or a system's inability to adequately capture, store and report transactions. The company has consistently maintained appropriate administrative controls for entering and administration of commodity transactions.

IV. Risk Management Strategy and Current Hedging Activity

Tampa Electric's risk management strategy is designed to limit exposure to different types of risk that are applicable to the company's operation.

A. Market Risk

Tampa Electric's potential market risk is the result of open positions in four commodities:

- Coal
- Natural Gas
- Fuel Oil
- Purchased Power

System energy requirements during ~~2013~~2014 are projected to be served in the proportions shown in the following table.

Commodity	Percent of System Energy
Coal	~~58~~59
Natural Gas	~~38~~37
No. 2 Oil	0
No. 6 Oil	0
Purchased Power	4

Based on Tampa Electric's assessment of market risk factors, the company has implemented the market risk management strategies described below.

1. **Coal:** Tampa Electric has contracted for much of its expected coal needs for ~~2013~~2014 through bilateral agreements with coal producers. The company will provide the projected amounts in both tons and dollars in its ~~2013~~2014 projection filing to be submitted August ~~31, 2012~~30, 2013. Coal market pricing has retreated from record high levels in 2008. In ~~2012~~2013, coal prices have been relatively stable, and prices are expected to remain stable in ~~2013~~2014. Tampa Electric has secured a portion of its coal needs for ~~2013~~2014, reducing exposure to price volatility and mitigating coal volume risk. Tampa Electric's contracts with suppliers also incorporate legal remedies in the event of default, which address volume risk.

2. **Fuel Oil:** In ~~2013~~2014, Tampa Electric will continue to purchase its fuel oil needs at indexed market prices. Oil represents less than one percent of the company's needs on a GWH basis, and

therefore, associated price impact from risk is minimal. Tampa Electric maintains a contract with a local supplier to deliver all of its needs, which mitigates supply risk.

3. **Natural Gas:** Tampa Electric continues to implement prudent financial hedging strategies for natural gas requirements. In ~~2012~~2013, the company used swap agreements—the exchange of a payment tied to the value of a natural gas index for a fixed payment—to hedge natural gas. In keeping with the company's approved risk management plan, Tampa Electric plans to hedge a significant percentage of its projected natural gas usage in ~~2013~~2014.

Tampa Electric uses the forward pricing information of the New York Mercantile Exchange ("NYMEX") natural gas forward price curve in developing natural gas price hedging strategy. Tampa Electric also subscribes to industry publications that provide information about underlying issues affecting the availability and price of natural gas and other commodities. The purpose of Tampa Electric's natural gas hedge plan is to reduce natural gas price volatility by utilizing financial instruments relying on three key variables: price, volume and time.

Tampa Electric projects prices during the company's annual fuel budgeting process. The volume of natural gas that the company will hedge falls between a minimum and a maximum percentage of the expected natural gas burn. The percentages vary according to the time remaining until the contract month.

Tampa Electric's approved Risk Management Plan describes the following key elements of the company's natural gas hedging strategy: (1) natural gas prices can be hedged up to 24 months into the future; (2) nearer months can be hedged for a greater percentage of the expected volume than outer months; and (3) natural gas options can be used for financial hedging.

Currently, Tampa Electric estimates ~~over~~ [redacted] about [redacted] percent of its total ~~2012~~2013 natural gas purchases will be covered by financial hedges. The net effect of these hedges is estimated to be a [redacted] of approximately [redacted]. For ~~2013~~2014, Tampa Electric has approximately [redacted] percent hedged with a currently estimated [redacted] of [redacted].

4. **Purchased Power:** Total forecasted purchased power for ~~2012~~2014 is ~~1,192~~713 GWH. As of July ~~2012~~2013, Tampa Electric has physically hedged ~~82~~328 GWH's of its ~~2013~~2014 expected purchased power needs through pre-scheduled purchased power

agreements. The remaining GWH's of ~~2013~~2014 forecasted wholesale energy purchases will be purchased from as-available cogenerators or on the short-term, non-firm market for economy purposes, which are not hedged.

The company's purchased power contracts include a fuel component; therefore, Tampa Electric has exposure to fuel price risk for its wholesale energy purchases, particularly for purchased power supplied from natural gas-fired generation. Tampa Electric does not currently hedge wholesale energy transactions with financial instruments due to the lack of a liquid, published wholesale energy market and appropriate available instruments.

Tampa Electric is responsible for natural gas fuel delivery on two purchase contracts for peaking power. Although this contract volume is not currently included in the company's hedging portfolio, Tampa Electric continually assesses whether it should be added.

In summary, Tampa Electric's planned operations in ~~2013~~2014 result in nominal market risk associated with coal and fuel oil. Non-price risks associated with natural gas and purchased power are also minimal. Therefore, while the company continues to evaluate risk for all fuel and energy commodity transactions, it is currently focused on mitigating the price risk associated with natural gas and purchased power.

5. **Volume Risk:** Hedging of volumetric risk is problematic due to a limited number of viable financial hedging instruments. Tampa Electric has identified the following hedges.
   - Maintaining appropriate inventory stockpiles provides a physical hedge against volume risk.
   - "Swing" contracts enable the buyer to take variable volumes up to a predefined limit.
   - Full requirement contracts enable the buyer to take any volume up to total usage.

   Tampa Electric uses inventory swing contracts and full requirements contracts where needed commodity volumes are small and in situations where commodity volumes are unpredictable in volume and/or timing. Other alternatives will continue to be identified, assessed and implemented as necessary.

6. **Credit Risk:** TECO Energy's credit risk management process is composed of the following primary steps.
   - Gather counterparty information for initial evaluation.
   - Assess counterparty creditworthiness and assign credit limit.
   - Determine credit collateral requirements, as needed.

- Request, review and monitor contractual requirements, legal covenants, collateral documents and credit provisions.
- Quantify counterparty exposure and measure against approved limits.
- Monitor counterparty and credit support provider qualities.
- Prepare credit exposure reports on a daily basis that are reviewed prior to entering into transactions.

7. **Administrative Risk:** Tampa Electric maintains energy trading risk management systems and processes to efficiently track, monitor and evaluate hedging activities. Tampa Electric's administrative processes and system controls have passed repeated internal and external (Sarbanes-Oxley) audits.

57. Regarding hedging activities, how does TECO assess and evaluate counter-party credit risk?

A. Pursuant to Tampa Electric's annual Risk Management Plan, most recently filed on August 2, 2013, the company's Risk Oversight Group negotiates the acceptable credit terms for each financial counterparty relationship, monitors and verifies internal daily transactions, establishes the credit underwriting and credit exposure standards, and monitors and evaluates the counterparty's credit limit to ensure thresholds are maintained.

58. For open hedging transactions since August 1, 2012, has TECO experienced any defaults by a counter-party? If so, please identify the counter-party and explain.

A. No, Tampa Electric has not experienced any counterparty defaults for open hedging transactions since August 1, 2012.

59. For all currently open hedging transactions, does TECO have any concern regarding default by a counter-party for any specific transaction? If so, please identify the counter-party and explain.

A. No. Tampa Electric currently does not have any heightened concerns regarding default by any counterparty for any specific transaction. Tampa Electric attempts to mitigate the credit risks associated with hedging through credit analysis and monitoring.

60. Since January 1, 2012, has TECO stopped engaging in hedging transactions with a particular counter-party due to credit risk concerns? If so, please identify the counter-party and explain.

A. No. Since January 1, 2012 Tampa Electric has not stopped engaging in hedging transactions with any counterparty due to credit risk concerns.

61. Has TECO incurred federal and/or state tax expenses (credits) on realized hedging gains (losses) over the past three years? If so, please provide the amount for each year and demonstrate whether such tax expenses (credits) have been appropriately recovered.

A. Tampa Electric's fuel expenses, including hedging gains or losses, are treated on a cash basis as the expense is incurred, for tax purposes. Recovery of fuel expenses, including hedging gains or losses, occurs through the fuel and purchased power cost recovery clause ("fuel clause"). The expenses or credits are recovered in the same manner that other fuel expense is treated.

When Tampa Electric realizes a gain due to hedging, Tampa Electric incurs a tax expense for the same calendar year based on the realized gain. Alternatively, when Tampa Electric realizes a loss due to hedging, Tampa Electric incurs a tax benefit (deduction) for the same calendar year based on the realized loss.

The annual gains or losses, determining tax rate and requested amount of tax expense or credit are shown in the following table.

Period	Gains/(Losses)	Tax Rate	Tax Expense/(Credit)
2010	($67,840,710)	38.575	($26,169,554)
2011	($33,889,480)	38.575	($13,072,867)
2012	($61,518,120)	38.575	($23,730,615)

Upon realization of a hedging gain or loss, Tampa Electric includes the amount for recovery or refund to ratepayers through the fuel clause. The recovery or refund amount is spread over the period for which the fuel clause factor is set.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is an Administrator, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Ninth Set of Interrogatories, (No. 50-61) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 15th day of October, 2013.

Penelope Rusk

Sworn to and subscribed before me this 15TH day of October, 2013.

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires

92

Staff's proposed revisions to GPIF manual No. 3.516

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 92
PARTY Florida Public Service Commission Staff
DESCRIPTION [Bates Nos. 690-691]

(Proposed) **Original Sheet No. 3.516 as Revised**

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	10,849,749,770
LINE 2	MONTH OF January	2012	$	10,983,930,940
LINE 3	MONTH OF February	2012	$	11,043,325,330
LINE 4	MONTH OF March	2012	$	11,128,965,610
LINE 5	MONTH OF April	2012	$	11,196,334,650
LINE 6	MONTH OF May	2012	$	11,333,068,500
LINE 7	MONTH OF June	2012	$	11,681,736,330
LINE 8	MONTH OF July	2012	$	11,828,681,570
LINE 9	MONTH OF August	2012	$	11,987,094,020
LINE 10	MONTH OF September	2012	$	12,073,906,876
LINE 11	MONTH OF October	2012	$	12,172,856,430
LINE 12	MONTH OF November	2012	$	12,463,562,700
LINE 13	MONTH OF December	2012	$	12,530,193,155
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	11,636,415,837
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			61.3808%
LINE 17	MAXIMUM INCENTIVE DOLLARS PER FINANCIAL DATA (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	47,394,364
LINE 18	JURISDICTIONAL SALES			102,225,549,000 KWH
LINE 19	TOTAL SALES			104,462,720,986 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			97.86%
LINE 21	MAXIMUM JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	46,380,125
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF-POINT LEVEL FROM SHEET NO. 3.515)		$	45,541,500
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$	45,541,500

Issued by: Florida Public Service Commission **Effective 1/1/2014**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 93
PARTY Florida Public Service Commission Staff
DESCRIPTION Confidential - Conf-1 [FPSC Document Nos. 01490-13, 02268-13, and 06292-13]

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI EXHIBIT 94

PARTY Florida Public Service Commission Staff

DESCRIPTION Confidential - Conf-2 [FPSC Document Nos. 01195-13 and 36238-13]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 95
PARTY Florida Public Service Commission Staff
DESCRIPTION Confidential - Conf-3 [FPSC Document Nos. 01171-13 and 06284-13]

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130001-EI EXHIBIT 96

PARTY Florida Public Service Commission Staff

DESCRIPTION Confidential - Conf-3 [FPSC Document Nos. 01205-13 and 06295-13]

EXHIBIT NO. 97

DOCKET NO:	**130001-EI**
WITNESS:	**Don Grissette**
PARTY:	**FPL**
DESCRIPTION:	**Corrected response to Staff's Ninth Set of Interrogatories No. 62**
DOCUMENTS:	**Corrected response to Staff's Ninth Set of Interrogatories No. 62 with Affidavit of Don Grissette dated November 1, 2013**
PROFFERED BY:	**FPL**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 97
PARTY Florida Power & Light Company
DESCRIPTION Don Grissette - Corrected response to Staff's Set of Interrogatories No. 62

Q.

The following questions relate to the August 2, 2013 testimony of Don Grissette filed in Docket No. 130001-EI.

Has FPL estimated a cost for the bulleted list on page 5 of the witness's testimony?

a. If yes, please provide FPL's estimates.

A.

FPL does not track the costs by the categories identified on the bulleted list on page 5 of the testimony and has not fully estimated the costs of the Fukushima Response Program at this time. However, FPL has identified a range of expected costs for the combined Turkey Point and St. Lucie effort which will fall within the categories identified on the bulleted list. The range is between $93M and $189M through the end of 2016. This estimate is for the cost of the proposed requirements in response to the immediate actions and does not include short term and long term requirements.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 1st day of November, 2013, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Don Grissette, who is personally known to me, and he acknowledged before me that he provided the corrected answer to interrogatory number 62 from STAFF'S NINTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT (NOS. 58-64) in Docket No. 130001-EI, and that the responses are true and correct based on his personal knowledge.

Don Grissette

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 1st day of November 2013.

LESLIE WHITWELL
MY COMMISSION EXPIRES
May 12, 2017
#EE 665053
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

Notary Public
State of Florida, at Large

My Commission Expires:
5-12-2017

EXHIBIT NO. 98

DOCKET NO: 130001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: RRSSA Excerpt

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 98
PARTY Duke Energy Florida
DESCRIPTION Thomas Foster - RRSSA Excerpt

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause	Docket No. 130009-EI
In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.	Docket No. 100437-EI
In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 130001-EI
In re: Environmental cost recovery clause	Docket No. 130007-EI
In re: Petition of Progress Energy Florida, Inc. to approve establishment of a regulatory asset and associated three-year amortization schedule for costs associated with PEF's previously approved thermal discharge compliance project.	Docket No. 130091-EI
In re: Petition of Duke Energy Florida, Inc. for limited proceeding to approve Revised and Restated Stipulation and Settlement Agreement, including certain Rate Adjustments.	Docket No. _____

REVISED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

WHEREAS, Duke Energy Florida, Inc. ("DEF" or the "Company"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate ("White Springs"), (collectively referenced as the "Parties"), previously resolved certain issues in a Stipulation and Settlement Agreement (the "2012 Settlement Agreement"), dated January 20, 2012, that was approved by the Florida

charged to the CR3 Decommissioning Trust Fund will not be added to the total CR3 Regulatory Asset value.

j. DEF shall exclude the following amounts related to CR3 from all surveillance reports: (1) revenues associated with the recovery of the CR3 Regulatory Asset base rate increase along with expenses (including, but not limited to, amortization); (2) rate base items (including, but not limited to, all amounts that have been deferred to or recorded in regulatory assets and liabilities); and (3) cost of capital accounts with specific adjustments for items including, but not limited to, deferred income taxes, with all other CR3-related items removed from capital structure on a pro-rata basis.

Fuel Adjustment Clause:

6. Refunds through the Fuel Adjustment Clause. Pursuant to the terms of this Revised and Restated Settlement Agreement, DEF agrees to the following:

a. Pursuant to the 2012 Settlement Agreement, DEF is refunding through the Fuel Adjustment Clause ("Fuel Clause") 50% of $258 million in 2013, and refunding the remaining 50% through the Fuel Clause in 2014. In addition, $30 million will be refunded through the Fuel Clause solely to customers on Rate Schedules RS-1, RSL-1, RSL-2, GS-1, and GS-2 (and their time-of-use counterpart schedules, to the extent applicable) based on an allocation of 94% of such refund amounts to the Residential Service rate schedules and 6% to the General Service, Non-Demand rate schedules, at an annual rate of $10 million per year in years 2014, 2015, and 2016.

b. DEF shall: (1) refund $40 million towards replacement fuel and purchased power costs in 2015; and (2) refund $60 million towards replacement fuel

and purchased power costs in 2016.

c. Except for the aforementioned refunds, DEF shall be entitled to recover its prudently incurred fuel and purchased power costs through the Fuel Clause without regard to the absence of CR3 for any reason for the period beginning October 1, 2009. DEF's right to recover its prudently incurred fuel and purchased power costs does not affect the rights of customers to receive reimbursement from NEIL proceeds for such costs as otherwise provided in this Revised and Restated Settlement Agreement. Thus, for the period beginning October 1, 2009, the unavailability of CR3 for any reason shall not be the basis for any disallowance of fuel or purchased power costs, and the Intervenor Parties waive their rights to challenge DEF's recovery of such costs, except that Intervenor Parties reserve the right to raise issues regarding the prudence and reasonableness of DEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the unavailability of CR3 for any reason.

7. Pursuant to the terms of this Revised and Restated Settlement Agreement, the Parties further agree to the following:

a. DEF shall be allowed to increase retail fuel rates as follows:

(i) 2014 - $1.00/mWh
(ii) 2015 - $1.00/mWh
(iii) 2016 - $1.50/mWh

These increases shall be added to the fuel factor at secondary metering consistent with the normal fuel projection process. All other fuel factors will be developed using the adjusted fuel factor at secondary metering in a manner consistent with the normal derivation of fuel factors. An example of this is shown in Exhibit 12 to this Revised and Restated Settlement Agreement for illustrative purposes using the

projected fuel costs and sales from Docket No. 120001-EI (actual costs and sales will be different when rates are set for 2014-2016). These rate increases are not cumulative but apply only for the years shown. For example, retail fuel rates will increase by $1.00/mWh in 2014, increase by an additional $.50/mWh in 2016 and decrease by $1.50/mWh in 2017. Revenues collected from these retail fuel rates will be calculated by multiplying the relevant $/mWh increase above times the jurisdictional mWh sales as reported in line 26 of Schedule A-1. These revenues will be removed from the fuel revenues for purposes of calculating the fuel true-up over/under recovery. As a result of the accelerated recovery of the carrying charge associated with the CR3 Regulatory Asset, DEF will not defer for recovery the carrying charge on the portion of the CR3 Regulatory Asset supported by these revenues. An example of this calculation is provided on Exhibit 11 to this Revised and Restated Settlement Agreement.

b. If DEF determines that additional funds are necessary in order to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3, DEF shall be allowed to petition to collect those additional funds through a surcharge in base rates. This surcharge will be the lesser of the Commission approved annual contribution amount or $8 million. The $8 million limitation shall expire with the last billing cycle for December 2018. After the last billing cycle for December 2018, DEF shall be authorized to recover the actual Commission approved annual contribution to the Nuclear Decommissioning Trust through a base rate surcharge, and that surcharge shall expire following the conclusion of DEF's next base rate case. If the Commission approves an annual contribution to the Nuclear Decommissioning Trust in excess of $8 million prior to the last billing cycle for December 2018, this incremental amount of the

annual contribution in excess of what has been authorized for recovery in the base rate surcharge shall be deferred with carrying costs based on the Commission approved allowance for funds used during construction ("AFUDC"), and recovered (including carrying costs) through the CCR Clause over a 4 year period beginning with the first billing cycle for January 2019, unless otherwise agreed to by the Parties. The Intervenor Parties reserve their rights to challenge the prudence of any additional CR3 decommissioning costs in appropriate proceedings before the Commission. The Parties expressly agree that any proceeding to recover costs associated with decommissioning CR3 under this paragraph shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve.

c. DEF shall credit the retail allocation of the NEIL settlement amount of $530 million (system), approximately $489 million (retail), through the Fuel Adjustment Clause beginning with the first billing cycle for January 2014.

d. DEF shall collect from customers the approximately $328 million (system), $326 million (retail) previously credited in the Fuel Adjustment Clause beginning with the first billing cycle for January 2014. Thus, the approximate net effect of paragraphs 7c and 7d above is that DEF will credit the NEIL CR3 settlement amount of $163 million (retail) through the Fuel Adjustment Clause beginning with the first billing cycle for January 2014.

e. Effective with the first billing cycle for January 2014, DEF shall change billing of the Retail CCR Clause for demand rate classes to be on a kilo-watt

EXHPAGE-000005

("kW") basis rather than the current kilo-watt-hour ("kWh") method. This requires a modification to Exhibit 5 to this Revised and Restated Settlement Agreement (which was also an exhibit to the 2012 Settlement Agreement), and that modification to Exhibit 5 is presented in Exhibit 9 to this Revised and Restated Settlement Agreement.

Crystal River 1 & 2 ("CRS") Retirement:

8. If DEF retires Crystal River coal units 1 & 2 ("Crystal River South" or "CRS"), as a compliance measure to meet Mercury and Air Toxics Standards ("MATS"), the Best Available Retrofit Technology ("BART"), and/or the National Ambient Air Quality Standards ("NAAQS"), DEF shall be permitted to continue the annual depreciation expense and depreciation rate associated with CRS based on the last Commission-approved depreciation study, which assumed a 2020 CRS retirement date. DEF shall be permitted to recover in 2021, unless a different time for recovery is agreed to by the Parties, any remaining CRS net book value existing at December 31, 2020 through the CCR Clause.

CR3 Extended Power Uprate project ("EPU" or "Uprate"):

9. a. DEF shall recover all CR3 EPU revenue requirements through the Nuclear Cost Recovery Clause ("NCRC") consistent with the provisions of Section 366.93(6), Florida Statutes ("F.S."), and Commission Rule 25-6.0423(6), F.A.C. with a seven (7) year amortization recovery period established as 2013-2019. Intervenor Parties fully and forever waive, release, discharge, and otherwise extinguish any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the prudence of DEF's CR3 EPU investment and activities, except that the Intervenor Parties do not waive their rights to participate in the NCRC or

Example of Recovery of CR3 Regulatory Asset Carrying Cost

Line		2014	2015	2016
1	Fuel Rate Increase ($/mWh)	$1.00	$1.00	$1.50
2	Multiply by Retail mWhs	x	x	x
3	Equals Total Revenue Recovered in Rates	$x	$x	$x
4	Less Income Tax Expense	-$x	-$x	-$x
5	Equals Avoided Increase in CR3 Regulatory Asset	$x	$x	$x

Note: The effects of the calculation on line 5 of this exhibit are incorporated in the final calculation of line 17 of exhibit 10.

EXHIBIT NO. 99

DOCKET NO: 130001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: DEF Summary of NEIL Reimbursement

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 99
PARTY Duke Energy Florida, Inc.
DESCRIPTION Thomas Foster
DEF Summary of NEIL Reimbursement

DUKE ENERGY FLORIDA
SUMMARY OF NEIL REIMBURSEMENT

TOTAL
$'s in millions

Year	NEIL Replacement Power Reimbursement	NEIL Replacement Capacity Reimbursement	NEIL Repair Reimbursement	NEIL Final Settlement	Total
2009	$ -	$ -	$ -	$ -	$ -
2010	$ 108	$ 4	$ 64	$ -	$ 176
2011	$ 39	$ -	$ 72	$ -	$ 111
2012	$ 11	$ -	$ 7	$ -	$ 18
2013	$ -	$ -	$ -	$ 530	$ 530
Total	$ 158	$ 4	$ 143	$ 530	$ 835

RETAIL
$'s in millions

Year	NEIL Replacement Power Reimbursement[1]	NEIL Replacement Capacity Reimbursement[2]	NEIL Repair Reimbursement[3]	NEIL Final Settlement[4]	Total
2009	$ -	$ -	$ -	$ -	$ -
2010	$ 100	$ 3	$ 54	$ -	$ 157
2011	$ 38	$ -	$ 61	$ -	$ 99
2012	$ 10	$ -	$ 6	$ -	$ 16
2013	$ -	$ -	$ -	$ 490	$ 490
Total	$ 148	$ 3	$ 121	$ 490	$ 762

[1] The retail portion of NEIL Replacement Power Reimbursement was passed through the Fuel Clause in the years shown.

[2] The retail portion of NEIL Replacement Capacity Reimbursement was passed through the Capacity Clause

[3] The retail portion of NEIL Repair Reimbursement was applied to CWIP

[4] The retail portion of the Final NEIL Settlement was passed through the Fuel Clause

EXHIBIT NO. 100

DOCKET NO: 130001-EI

WITNESS: Foster

PARTY: Duke Energy Florida

DESCRIPTION: Composite 2013 & 2014 True-Up Schedules
(Hearing Exhibits 25 & 26 Excerpts)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 100
PARTY Duke Energy Florida, Inc.
DESCRIPTION Thomas Foster - Composite 2013 & 2014
True-up Schedules (Hearing Exhibits 25 & 26

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2013

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 105,743,586	$ 97,112,812	$ 110,347,311	$ 117,890,107	$ 126,232,404	$ 147,371,377	$ 704,697,597
	2	Fuel Cost of Power Sold	(3,047,976)	(2,326,177)	(2,554,581)	(3,037,857)	(5,011,053)	(4,283,713)	(20,261,358)
	3	Fuel Cost of Purchased Power	4,993,222	7,400,788	8,066,615	11,342,391	10,281,566	19,239,698	61,324,281
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	19,749,624	16,442,524	18,086,280	16,205,598	18,334,050	19,697,765	108,515,841
	4	Energy Cost of Economy Purchases	236,354	157,429	583,403	943,332	2,291,585	3,281,318	7,493,422
	5	Adjustments to Fuel Cost	(14,542,710)	(11,782,902)	(12,003,796)	(12,497,267)	(507,889,089)	(11,979,214)	(570,694,978)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	113,132,100	107,004,475	122,525,232	130,846,304	(355,760,537)	173,327,232	291,074,805
B	1	Jurisdictional KWH Sales	2,608,843	2,578,190	2,542,535	2,678,410	3,007,039	3,332,396	16,747,413
	2	Non-Jurisdictional KWH Sales	19,110	16,403	14,531	17,654	13,320	20,035	101,053
	3	TOTAL SALES (Lines B1 + B2)	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	16,848,466
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	93,290,375	92,122,713	90,898,588	96,136,174	109,403,698	122,302,252	604,153,799
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(72,683,454)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(747,786)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	81,051,835	79,884,173	78,660,048	83,897,634	97,165,158	110,063,712	530,722,559
	4	Fuel & Net Power Transactions (Line A6)	113,132,100	107,004,475	122,525,232	130,846,304	(355,760,537)	173,327,232	291,074,805
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	112,443,249	106,489,842	122,009,579	130,190,797	(354,726,484)	172,545,699	288,952,682
	6	Over/(Under) Recovery (Line C3 - Line C5)	(31,391,414)	(26,605,669)	(43,349,531)	(46,293,163)	451,891,642	(62,481,987)	241,769,878
	7	Interest Provision	(13,633)	(19,529)	(21,369)	(20,997)	(5,103)	6,088	(74,542)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(31,405,047)	(26,625,199)	(43,370,900)	(46,314,160)	451,886,539	(62,475,899)	241,695,335
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	12,113,909	24,227,818	36,341,727	48,455,636	60,569,545	72,683,454	72,683,454
	11	Subtotal Prior Period True-up	(205,463,691)	(193,349,782)	(181,235,873)	(169,121,964)	(157,008,055)	(144,894,146)	(144,894,146)
	12	Regulatory Accounting Adjustment	-	-	(229,070)	-	37,080	-	(191,990)
	13	TOTAL TRUE-UP BALANCE	($236,868,738)	(251,380,027)	($282,866,088)	($317,066,339)	$146,971,190	$96,609,199	$96,609,199

EXHPAGE-000001

Exhibit TGF-2, Part 1

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of: January through December 2013

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 145,250,812	$ 150,607,717	$ 136,985,940	$ 114,538,238	$ 107,075,208	$ 108,923,607	$ 1,468,079,120
	2	Fuel Cost of Power Sold	(5,569,460)	(5,527,090)	(5,386,128)	(4,969,913)	(3,255,666)	(2,375,290)	(47,344,905)
	3	Fuel Cost of Purchased Power	23,957,592	25,094,990	21,710,075	18,555,272	9,554,987	6,499,016	166,696,213
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	18,004,359	13,089,077	12,644,871	11,903,930	12,657,284	15,760,883	192,576,244
	4	Energy Cost of Economy Purchases	1,756,060	1,775,447	1,776,669	1,742,573	915,791	706,536	16,166,498
	5	Adjustments to Fuel Cost	(10,817,565)	(10,821,916)	(10,826,271)	(10,828,450)	(10,827,360)	(10,816,477)	(635,633,018)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
B	1	Jurisdictional KWH Sales	3,583,405	3,748,970	3,752,239	3,277,587	2,841,165	2,732,348	36,683,127
	2	Non-Jurisdictional KWH Sales	18,864	21,241	22,661	20,547	17,439	14,034	215,839
	3	TOTAL SALES (Lines B1 + B2)	3,602,269	3,770,211	3,774,900	3,298,134	2,858,604	2,746,382	36,898,966
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.48%	99.44%	99.40%	99.38%	99.39%	99.49%	99.42%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	132,431,293	138,550,051	138,670,863	121,129,229	105,000,455	100,978,923	1,340,914,612
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,909)	(12,113,913)	(145,366,912)
	2a	Incentive Provision	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(124,631)	(1,495,572)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	120,192,753	126,311,511	126,432,323	108,890,689	92,761,915	88,740,380	1,194,052,129
	4	Fuel & Net Power Transactions (Line A6)	172,581,798	174,218,225	156,905,155	130,941,650	116,120,243	118,698,275	1,160,540,151
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	171,941,900	173,502,467	156,197,670	130,325,007	115,585,027	118,270,053	1,154,774,805
	6	Over/(Under) Recovery (Line C3 - Line C5)	(51,749,146)	(47,190,956)	(29,765,347)	(21,434,318)	(22,823,112)	(29,529,674)	39,277,324
	7	Interest Provision	3,842	1,974	656	(18)	(519)	(1,222)	(69,830)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(51,745,304)	(47,188,981)	(29,764,691)	(21,434,336)	(22,823,632)	(29,530,897)	39,207,494
	9	Plus: Prior Period Balance	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)	(217,577,600)
	10	Plus: Cumulative True-Up Provision	84,797,363	96,911,272	109,025,181	121,139,090	133,252,999	145,366,912	145,366,912
	11	Subtotal Prior Period True-up	(132,780,237)	(120,666,328)	(108,552,419)	(96,438,510)	(84,324,601)	(72,210,688)	(72,210,688)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	(191,990)
	13	TOTAL TRUE-UP BALANCE	$56,977,803	$21,902,731	$4,251,949	($5,068,478)	($15,778,200)	($33,195,183)	($33,195,183)

Docket No. 130001-EI
Exhibit TGF-2, Part 1
Schedule E1-B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
Duke Energy Florida
Estimated for the Period of : January through December 2013

		DOLLARS				MWH				c/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %
1	Fuel Cost of System Net Generation (E3)	1,468,079,120	1,361,604,286	106,474,833	8%	33,103,741	33,752,262	(648,521)	-2%	4.435	4.034	0.401	10%
2	Spent Nuclear Fuel Disposal Cost	0	0	-	0%	0	0	-	0%	0.000	0.000	0.000	0%
3	Coal Car Investment	0	0	-	0%			-		0.000	0.000	0.000	
4	Adjustment to Fuel Cost	(635,633,018)	(456,990,441)	(178,642,576)	0%			-		0.000	0.000	0.000	
5	TOTAL COST OF GENERATED POWER	832,446,102	904,613,845	(72,167,743)	-8%	33,103,741	33,752,262	(648,521)	-2%	2.515	2.680	-0.165	-6%
6	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	166,696,213	197,756,948	(31,060,735)	-16%	3,014,077	3,758,406	(744,329)	-20%	5.531	5.262	0.269	5%
				-				-		0.000	0.000	0.000	
7	Energy Cost of Economy Purchases (E9)	16,166,498	11,096,755	5,069,743	46%	275,451	182,273	93,178	51%	5.869	6.088	-0.219	
8	Payments to Qualifying Facilities (E8)	192,576,244	161,948,287	30,627,957	19%	4,034,436	3,479,980	554,456	16%	4.773	4.654	0.120	3%
9	TOTAL COST OF PURCHASED POWER	375,438,955	370,801,990	4,636,965	1%	7,323,963	7,420,659	(96,696)	-1%	5.126	4.997	0.129	3%
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)			-		40,427,704	41,172,921	(745,217)	-2%	0.000	0.000	0.000	
11	Fuel Cost of Economy Sales (E6)	(2,238,922)	(2,813,022)	574,100	-20%	(64,589)	(78,416)	13,827	-18%	3.466	3.587	-0.121	-3%
11a	Gain on Economy Sales (E6)	(509,875)	(365,693)	(144,182)	39%	(64,589)	(78,416)	13,827	-18%	0.789	0.466	0.323	69%
12	Fuel Cost of Stratified Sales (E6)	(44,596,108)	(36,175,371)	(8,420,738)	23%	(1,182,948)	(1,209,795)	26,847	-2%	3.770	2.990	0.780	26%
13	TOTAL FUEL COST AND GAINS OF POWER SALES (LINES 11 + 11a + 12)	(47,344,905)	(39,354,086)	(7,990,820)	20%	(1,247,537)	(1,288,211)	40,674	-3%	3.795	3.055	0.740	24%
14	Net Inadvertent Interchange					113,112		113,112					
15	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 9 + 13 + 14)	1,160,540,151	1,236,061,749	(75,521,598)	-6%	39,293,279	39,884,710	(591,431)	-1%	2.954	3.099	-0.146	-5%
16	Net Unbilled					157,820	(35,330)	193,150	-547%	0.000	0.000	0.000	
17	Company Use					(146,735)	(144,000)	(2,735)	2%	0.000	0.000	0.000	
18	T & D Losses					(2,405,398)	(2,208,703)	(196,695)	9%	0.000	0.000	0.000	
19	SYSTEM KWH SALES	1,160,540,151	1,236,061,749	(75,521,598)	-6%	36,898,966	37,496,677	(597,711)	-2%	3.145	3.296	-0.151	-5%
20	Wholesale KWH Sales	(7,463,516)	(2,856,630)	(4,606,886)	161%	(215,839)	(113,303)	(102,536)	90%	3.458	2.521	0.937	37%
21	Jurisdictional KWH Sales	1,153,076,636	1,233,205,120	(80,128,484)	-6%	36,683,127	37,383,374	(700,247)	-2%	3.143	3.299	-0.155	-5%
21a	Jurisdictional Loss Multiplier	1.0015	1.00122	0	0%	1.0015	1.00122	0	0%				
22	Jurisdictional Sales Adjusted for Line Losses	1,154,774,804	1,234,709,629	(79,934,825)	-6%	36,683,127	37,383,374	(700,247)	-2%	3.148	3.303	-0.155	-5%
23	TRUE-UP **	217,577,600	145,366,912	72,210,688	50%	36,683,127	37,383,374	(700,247)	-2%	0.593	0.389	0.204	53%
24	TOTAL JURISDICTIONAL FUEL COST	1,372,352,404	1,380,076,540	(7,724,137)	-1%	36,683,127	37,383,374	(700,247)	-2%	3.741	3.692	0.049	1%
25	Revenue Tax Factor	988,094	993,655	(5,561)	-1%								
26	Fuel Factor Adjusted for Taxes	1,373,340,497	1,381,070,196	(7,729,698)	-1%	36,683,127	37,383,374	(700,247)	-2%	3.744	3.694	0.049	1%
27	GPIF **	1,495,572	1,495,572	-	0%	36,683,127	37,383,374	(700,247)	-2%	0.004	0.004	0.000	2%
28	Fuel Factor Adjusted for Taxes Including GPIF	1,374,836,069	1,382,565,768	(7,729,698)	-1%	36,683,127	37,383,374	(700,247)	-2%	3.748	3.698	0.050	1%
29	FUEL FACTOR ROUNDED TO NEAREST .001 c/KWH									3.748	3.698	0.050	1%

* Included for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2013

			Actual Jan-13	Actual Feb-13	Actual Mar-13	Actual Apr-13	Actual May-13	Actual Jun-13	Estimated Jul-13	Estimated Aug-13	Estimated Sep-13	Estimated Oct-13	Estimated Nov-13	Estimated Dec-13	TOTAL
	Fuel Cost of System Net Generation		$105,743,586	$97,112,812	$110,347,311	$117,890,107	$126,232,404	$147,371,377	$145,250,812	$150,607,717	$136,985,940	$114,538,238	$107,075,208	$108,923,607	$1,468,079,120
a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Adjustments to Fuel Cost		(14,542,710)	(11,782,902)	(12,003,796)	(12,497,267)	(507,889,089)	(11,979,214)	(10,817,565)	(10,821,916)	(10,826,271)	(10,828,450)	(10,827,360)	(10,816,477)	(635,633,018)
	Fuel Cost of Power Sold		(62,075)	(145,944)	(270,085)	(321,292)	(80,886)	(204,859)	(484,794)	(293,697)	(55,842)	(241,586)	(46,452)	(31,410)	(2,238,922)
a	Gains on Power Sales		(11,835)	(30,429)	(48,239)	(89,128)	(14,863)	(73,087)	(101,807)	(61,676)	(11,727)	(50,733)	(9,756)	(6,596)	(509,875)
b	Fuel Cost of Stratified Sales		(2,974,066)	(2,149,805)	(2,236,257)	(2,627,437)	(4,915,305)	(4,005,767)	(4,982,859)	(5,171,717)	(5,318,559)	(4,677,594)	(3,199,458)	(2,337,284)	(44,596,108)
	Fuel Cost of Purchased Power (Excl Economy)		4,993,222	7,400,788	8,066,615	11,342,391	10,281,566	19,239,698	23,957,592	25,094,990	21,710,075	18,555,272	9,554,987	6,499,016	166,696,213
a	Energy Payments to Qualifying Facilities		19,749,624	16,442,524	18,086,280	16,205,598	18,334,050	19,697,765	18,004,359	13,089,077	12,644,871	11,903,930	12,657,284	15,760,883	192,576,244
	Energy Cost of Economy Purchases		236,354	157,429	583,403	943,332	2,291,585	3,281,318	1,756,060	1,775,447	1,776,669	1,742,573	915,791	706,536	16,166,498
	Total System Fuel & Net Power Transactions		$113,132,100	$107,004,475	$122,525,232	$130,846,304	($355,760,537)	$173,327,232	$172,581,798	$174,218,225	$156,905,155	$130,941,650	$116,120,243	$118,698,275	$1,160,540,151
	Jurisdictional MWH Sold		2,608,843	2,578,190	2,542,535	2,678,410	3,007,039	3,332,396	3,583,405	3,748,970	3,752,239	3,277,587	2,841,165	2,732,348	36,683,127
	Jurisdictional % of Total Sales		99.27%	99.37%	99.43%	99.35%	99.56%	99.40%	99.48%	99.44%	99.40%	99.38%	99.39%	99.49%	99.42%
	Jurisdicitonal Fuel & Net Power Transactions		112,306,235	106,330,346	121,826,838	129,995,803	(354,195,191)	172,287,268	171,684,373	173,242,603	155,963,724	130,129,812	115,411,909	118,092,914	1,153,076,636
	Jurisdictional Loss Multiplier		1.00122	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150
0	Jurisdictional Fuel & Net Power Transactions		112,443,249	106,489,842	122,009,579	130,190,797	(354,726,484)	172,545,699	171,941,900	173,502,467	156,197,670	130,325,007	115,585,027	118,270,053	1,154,774,805
1	Adjusted System Sales	MWH	2,627,952	2,594,593	2,557,065	2,696,064	3,020,359	3,352,431	3,602,269	3,770,211	3,774,900	3,298,134	2,858,604	2,746,382	36,898,966
2	System Cost per KWH Sold	c/kwh	4.3050	4.1242	4.7917	4.8533	-11.7787	5.1703	4.7909	4.6209	4.1565	3.9702	4.0621	4.3220	3.1452
3	Jurisdictional Loss Multiplier	x	1.00122	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.00150
4	Jurisdictional Cost per KWH Sold	c/kwh	4.3101	4.1304	4.7987	4.8607	-11.7965	5.1778	4.7983	4.6280	4.1628	3.9762	4.0682	4.3285	3.1480
5	Prior Period True-Up	+	0.6950	0.7033	0.7131	0.6770	0.6030	0.5441	0.5060	0.4836	0.4832	0.5532	0.6382	0.6636	0.5931
6	Total Jurisdictional Fuel Expense	c/kwh	5.0051	4.8337	5.5119	5.5377	-11.1936	5.7219	5.3043	5.1116	4.6460	4.5294	4.7064	4.9921	3.7411
7	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
8	Recovery Factor Adjusted for Taxes	c/kwh	5.0087	4.8372	5.5158	5.5417	-11.2016	5.7260	5.3081	5.1153	4.6494	4.5327	4.7098	4.9957	3.7438
9	GPIF	+	0.0048	0.0048	0.0049	0.0047	0.0041	0.0037	0.0035	0.0033	0.0033	0.0038	0.0044	0.0046	0.0041
0	Total Recovery Factor (rounded .001)	c/kwh	5.013	4.842	5.521	5.546	-11.197	5.730	5.312	5.119	4.653	4.537	4.714	5.000	3.748

Duke Energy Florida
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January through December 2014

1.	Actual Over/(Under) Recovery January - December 2012. (Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec '12)	$	(217,577,600)
2.	Projected (Over)/Under Recovery January - December 2012 . (Refunded)/Collected January - December 2012 . (Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec '12)	$	145,366,912
3.	Estimated Over/(Under) Recovery January - December 2013 (Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec '13)	$	39,015,505
4.	Total Over/(Under) Recovery to be Included in the January - December 2013 Projected Period (Lines 1 through 3)	$	(33,195,183)
5.	Jurisdictional mWh Sales (Projected Period)	mWh	37,664,779
6.	True-Up Factor (Line 4 / Line 5)	Cents/kWh	0.088

Duke Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January through December 2014

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	3,262,447
	B. True-Up (Over) / Under Recovery	$	33,195,183
2.	JURISDICTIONAL mWh SALES	mWh	37,664,779
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.009
	B. True-Up Factor	Cents/kWh	0.088

CALCULATION OF ESTIMATED TRUE-UP
(12 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JAN ESTIMATED	FEB ESTIMATED	MAR ESTIMATED	APR ESTIMATED	MAY ESTIMATED	JUN ESTIMATED	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 109,697,450	$ 98,055,406	$ 102,409,303	$ 109,857,132	$ 131,525,689	$ 133,094,832	$ 684,639,814
	2	Fuel Cost of Power Sold	(2,803,915)	(3,204,332)	(1,573,292)	(2,397,957)	(3,953,778)	(3,147,549)	(17,080,824)
	3	Fuel Cost of Purchased Power	10,366,631	8,730,628	13,494,162	12,905,539	16,967,603	23,495,283	85,959,846
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	12,290,083	11,165,902	11,080,558	9,903,257	12,009,955	11,675,501	68,125,257
	4	Energy Cost of Economy Purchases	633,441	557,310	1,061,389	1,184,454	1,459,788	1,406,780	6,303,162
	5	Adjustments to Fuel Cost	(9,721,268)	(10,823,336)	(10,801,583)	(10,796,158)	(10,802,668)	(10,801,583)	(63,746,595)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	120,462,423	104,481,578	115,670,538	120,656,267	147,206,589	155,723,264	764,200,660
B	1	Jurisdictional KWH Sales	2,853,337	2,664,980	2,618,503	2,721,614	2,943,262	3,503,630	17,305,326
	2	Non-Jurisdictional KWH Sales	15,639	18,564	12,889	12,147	14,850	17,380	91,469
	3	TOTAL SALES (Lines B1 + B2)	2,868,976	2,683,544	2,631,392	2,733,761	2,958,112	3,521,010	17,396,795
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.45%	99.31%	99.51%	99.56%	99.50%	99.51%	99.47%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	122,684,313	114,585,568	112,587,206	117,020,648	126,550,799	150,644,820	744,073,354
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(16,597,590)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(1,631,226)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	119,646,177	111,547,432	109,549,070	113,982,512	123,512,663	147,606,684	725,844,538
	4	Fuel & Net Power Transactions (Line A6)	120,462,423	104,481,578	115,670,538	120,656,267	147,206,589	155,723,264	764,200,660
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	119,979,579	103,916,296	115,276,408	120,305,568	146,690,262	155,192,661	761,360,774
	6	Over/(Under) Recovery (Line C3 - Line C5)	(333,402)	7,631,135	(5,727,338)	(6,323,056)	(23,177,599)	(7,585,977)	(35,516,236)
	7	Interest Provision	(1,597)	(1,276)	(1,090)	(1,253)	(1,852)	(2,483)	(9,552)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(334,999)	7,629,859	(5,728,428)	(6,324,309)	(23,179,452)	(7,588,459)	(35,525,788)
	9	Plus: Prior Period Balance	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)
	10	Plus: Cumulative True-Up Provision	2,766,265	5,532,530	8,298,795	11,065,060	13,831,325	16,597,590	16,597,590
	11	Subtotal Prior Period True-up	(30,428,918)	(27,662,653)	(24,896,388)	(22,130,123)	(19,363,858)	(16,597,593)	(16,597,593)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($30,763,917)	($20,367,793)	($23,329,956)	($26,888,000)	($47,301,187)	($52,123,382)	($52,123,382)

CALCULATION OF ESTIMATED TRUE-UP
(12 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2014

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 139,588,791	$ 143,678,496	$ 131,196,571	$ 114,775,399	$ 96,807,605	$ 104,617,700	$ 1,415,304,375
	2	Fuel Cost of Power Sold	(4,414,177)	(5,997,006)	(4,695,441)	(4,385,374)	(3,226,757)	(1,692,798)	(41,492,376)
	3	Fuel Cost of Purchased Power	23,165,512	23,634,893	20,625,684	17,745,201	12,332,688	10,445,497	193,909,321
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	11,730,800	11,857,186	11,445,495	11,414,923	10,688,803	12,316,104	137,578,568
	4	Energy Cost of Economy Purchases	1,302,455	1,234,821	1,429,756	1,484,812	1,024,770	778,977	13,558,753
	5	Adjustments to Fuel Cost	(10,817,889)	(10,824,426)	(10,827,697)	(10,828,879)	(10,821,157)	(10,805,928)	(128,673,569)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	160,555,492	163,583,964	149,174,368	130,205,083	106,805,953	115,659,554	1,590,185,072
B	1	Jurisdictional KWH Sales	3,674,816	3,817,582	3,828,744	3,358,467	2,905,863	2,773,981	37,664,779
	2	Non-Jurisdictional KWH Sales	23,785	26,898	28,347	25,523	19,658	14,808	230,488
	3	TOTAL SALES (Lines B1 + B2)	3,698,601	3,844,480	3,857,091	3,383,990	2,925,521	2,788,789	37,895,267
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.36%	99.30%	99.27%	99.25%	99.33%	99.47%	99.39%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	158,005,268	164,143,746	164,623,677	144,403,278	124,942,762	119,272,260	1,619,464,346
	1a	Adjustments to Fuel Revenue	-	-	-	-	-	-	-
	2	True-Up Provision	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,265)	(2,766,268)	(33,195,183)
	2a	Incentive Provision	(271,871)	(271,871)	(271,871)	(271,871)	(271,871)	(271,866)	(3,262,447)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	154,967,132	161,105,610	161,585,541	141,365,142	121,904,626	116,234,126	1,583,006,715
	4	Fuel & Net Power Transactions (Line A6)	160,555,492	163,583,964	149,174,368	130,205,083	106,805,953	115,659,554	1,590,185,072
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	159,767,228	162,682,534	148,307,523	129,422,388	106,249,488	115,219,128	1,583,009,064
	6	Over/(Under) Recovery (Line C3 - Line C5)	(4,800,097)	(1,576,924)	13,278,018	11,942,755	15,655,138	1,014,998	(2,348)
	7	Interest Provision	(2,654)	(2,675)	(2,245)	(1,476)	(648)	(93)	(19,344)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(4,802,751)	(1,579,599)	13,275,773	11,941,278	15,654,489	1,014,904	(21,692)
	9	Plus: Prior Period Balance	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)	(33,195,183)
	10	Plus: Cumulative True-Up Provision	19,363,855	22,130,120	24,896,385	27,662,650	30,428,915	33,195,183	33,195,183
	11	Subtotal Prior Period True-up	(13,831,328)	(11,065,063)	(8,298,798)	(5,532,533)	(2,766,268)	-	-
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($54,159,868)	($52,973,202)	($36,931,164)	($22,223,620)	($3,802,866)	($21,692)	($21,692)

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2014

			Estimated Jan-14	Estimated Feb-14	Estimated Mar-14	Estimated Apr-14	Estimated May-14	Estimated Jun-14	Estimated Jul-14	Estimated Aug-14	Estimated Sep-14	Estimated Oct-14	Estimated Nov-14	Estimated Dec-14	TOTAL
1	Fuel Cost of System Net Generation		$109,697,450	$98,055,406	$102,409,303	$109,857,132	$131,525,689	$133,094,832	$139,588,791	$143,676,496	$131,198,571	$114,775,399	$96,807,605	$104,617,700	$1,415,304,375
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(9,721,288)	(10,823,336)	(10,801,583)	(10,796,158)	(10,802,668)	(10,801,583)	(10,817,889)	(10,824,426)	(10,827,697)	(10,828,879)	(10,821,157)	(10,805,926)	(128,673,569)
2	Fuel Cost of Power Sold		(373,584)	(781,759)	(27,975)	(48,483)	(962,079)	(7,485)	(124,621)	(1,087,424)	(6,071)	(47,591)	(41,270)	(2,545)	(3,510,887)
2a	Gains on Power Sales		(78,453)	(164,169)	(5,875)	(10,182)	(202,036)	(1,572)	(26,170)	(228,359)	(1,275)	(9,994)	(8,667)	69,500	(667,252)
2b	Fuel Cost of Stratified Sales		(2,351,678)	(2,258,404)	(1,539,442)	(2,339,292)	(2,789,663)	(3,138,492)	(4,263,386)	(4,661,223)	(4,688,095)	(4,327,789)	(3,176,820)	(1,759,753)	(37,314,237)
3	Fuel Cost of Purchased Power (Exd Economy)		10,366,631	8,730,626	13,484,162	12,905,539	15,987,603	23,495,283	23,165,512	23,634,893	20,625,684	17,745,201	12,332,688	10,445,497	193,909,321
3a	Energy Payments to Qualifying Facilities		12,290,083	11,165,902	11,080,558	9,903,257	12,009,955	11,575,501	11,730,800	11,857,186	11,445,495	11,414,923	10,688,803	12,316,104	137,578,568
4	Energy Cost of Economy Purchases		633,441	557,310	1,061,389	1,184,454	1,459,788	1,406,780	1,302,455	1,234,821	1,429,756	1,484,812	1,024,770	778,977	13,558,753
5	Total System Fuel & Net Power Transactions		$120,462,423	$104,481,578	$115,570,538	$120,656,267	$147,206,589	$155,723,284	$160,555,492	$163,583,964	$149,174,368	-$130,205,083	$106,805,953	$115,659,554	$1,590,185,072
6	Jurisdictional mWh Sold		2,853,337	2,664,980	2,618,503	2,721,614	2,943,262	3,503,630	3,674,816	3,817,582	3,828,744	3,358,467	2,905,863	2,773,981	37,864,779
7	Jurisdictional % of Total Sales		99.45%	99.31%	99.51%	99.58%	99.50%	99.51%	99.36%	99.30%	99.27%	99.25%	99.33%	99.47%	99.39%
8	Jurisdictional Fuel & Net Power Transactions		119,799,879	103,760,655	115,103,752	120,125,379	146,470,556	154,960,220	159,527,936	162,438,876	148,085,395	129,228,545	106,090,353	115,046,558	1,580,638,106
9	Jurisdictional Loss Multiplier		1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150	1.00150
10	Jurisdictional Fuel & Net Power Transactions		119,979,579	103,916,296	115,276,408	120,305,568	146,690,262	155,192,661	159,767,228	162,682,534	148,307,523	129,422,388	106,249,488	115,219,128	1,583,009,064
11	Adjusted System Sales	mWh	2,868,976	2,683,544	2,631,392	2,733,761	2,958,112	3,521,010	3,698,601	3,844,480	3,857,091	3,383,990	2,925,521	2,788,789	37,895,267
12	System Cost per kWh Sold	c/kWh	4.1989	3.8934	4.3958	4.4136	4.9764	4.4226	4.3410	4.2550	3.8675	3.8477	3.6508	4.1473	4.1963
13	Jurisdictional Loss Multiplier	x	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.00150
14	Jurisdictional Cost per kWh Sold	c/kWh	4.2049	3.8993	4.4024	4.4204	4.9839	4.4295	4.3476	4.2614	3.8735	3.8536	3.6564	4.1536	4.2029
15	Prior Period True-Up	+	0.0970	0.1038	0.1056	0.1016	0.0940	0.0790	0.0753	0.0725	0.0723	0.0824	0.0952	0.0997	0.0861
16	Total Jurisdictional Fuel Expense	c/kWh	4.3018	4.0031	4.5080	4.5220	5.0779	4.5084	4.4229	4.3339	3.9458	3.9360	3.7516	4.2533	4.2910
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kWh	4.3049	4.0060	4.5113	4.5253	5.0818	4.5117	4.4261	4.3370	3.9486	3.9388	3.7543	4.2564	4.2941
19	GPIF	+	0.0095	0.0102	0.0104	0.0100	0.0092	0.0078	0.0074	0.0071	0.0071	0.0081	0.0094	0.0098	0.0087
20	Total Recovery Factor (rounded .001)	c/kWh	4.314	4.016	4.522	4.535	5.091	4.519	4.433	4.344	3.956	3.947	3.764	4.266	4.303

Duke Energy Florida
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January through December 2014

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 22)	$ 1,583,009,063	
1a.	Prior Period True-up (E1, Line 23)	$ 33,195,183	
2.	Regulatory Assessment Fee (E1, Line 25)	$ 1,163,667	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 27)	$ 3,262,447	
4.	Total amount to be Recovered	$ 1,620,630,360	
5.	Jurisdictional Sales (January - December 2014)	37,664,779	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)	4.303	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)	37,616,661	mWh
	LEVELIZED FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):		
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)	4.308	Cents/kWh
9.	Fuel Factor Adjustment pursuant to 2013 Revised and Restated Stipulation and Settlement Agreement	0.100	Cents/kWh
10.	Adjusted Fuel Factor at Secondary Metering (Line 8 + Line 9)	4.408	Cents/kWh
11.	Fuel Factor at Primary Metering	4.364	Cents/kWh
12.	Fuel Factor at Transmission Metering	4.320	Cents/kWh
	LEVELIZED FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):		
13.	2012 Settlement Agreement Refund (per Order No. PSC-12-0104-FOF-EI)*	$ (9,400,000)	
14.	Interest Amortization on Settlement Agreement Refund*	$ (51,863)	
15.	Applicable Jurisdictional Sales at Secondary Metering**	19,379,756	mWh
16.	Fuel Factor at Secondary Metering Rate Adjustment (Line 13 + Line 14 / Line 15 / 10)	(0.049)	Cents/kWh
17.	Fuel Factor at Secondary Metering (Line 10 + Line 16)	4.359	Cents/kWh
	LEVELIZED FUEL FACTORS (only GS-1, GST-1 & GS-2):		
18.	2012 Settlement Agreement Refund (per Order No. PSC-12-0104-FOF-EI)*	$ (600,000)	
19.	Interest Amortization on Settlement Agreement Refund*	$ (3,310)	
20.	Applicable Jurisdictional Sales at Secondary Metering**	1,384,634	mWh
21.	Fuel Factor at Secondary Metering Rate Adjustment (Line 18 + Line 19 / Line 20 / 10)	(0.044)	Cents/kWh
22.	Fuel Factor at Secondary Metering (Line10 + Line 21)	4.364	Cents/kWh
23.	Fuel Factor at Primary Metering	4.320	Cents/kWh
24.	Fuel Factor at Transmission Metering	4.277	Cents/kWh
	TIERED FUEL FACTORS:		
25.	Fuel Factor - First Tier (0-1000 kWh)	4.077	Cents/kWh
26.	Fuel Factor - Second Tier (Over 1000 kWh)	5.077	Cents/kWh

* The 2012 Settlement Agreement refunds and associated interest included on lines 13-14 and 18-19 are consistent with and included in the 2013 Revised and Restated Stipulation and Settlement Agreement, which is subject to approval by the Commission.

** Applicable Jurisdictional Sales at Secondary Metering utilized in the calculation of the 2012 Settlement Agreement Refund Fuel Factor Adjustment (lines 15 & 20) are a subset of the Effective Jurisdictional Sales reported above on line 7.

METERING VOLTAGE:	JURISDICTIONAL SALES (mWh) METER	SECONDARY
Distribution Secondary	33,218,915	33,218,915
Distribution Primary	4,079,897	4,039,098
Transmission	365,967	358,648
Total	37,664,779	37,616,661

Duke Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January through December 2014

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	Time of Use: On-Peak Multiplier 1.291	Time of Use: Off-Peak Multiplier 0.858
	FUEL FACTORS (excl RS-1, RST-1, RSL-1, RSL-2, RSS-1, GS-1, GST-1 & GS-2):					
1.	Distribution Secondary	–	–	4.408	5.691	3.782
2.	Distribution Primary	–	–	4.364	5.634	3.744
3.	Transmission	–	–	4.320	5.577	3.707
4.	Lighting Service	–	–	4.139	–	–
	Line 4 calculated at secondary rate of 4.408 * (18.7% * On-Peak Multiplier 1.291 + 81.3% * Off-Peak Multiplier 0.858).					
	FUEL FACTORS (only RS-1, RST-1, RSL-1, RSL-2 & RSS-1):					
5.	Distribution Secondary	4.077	5.077	4.359	5.627	3.740
	FUEL FACTORS (only GS-1, GST-1 & GS-2):					
6.	Distribution Secondary	–	–	4.364	5.634	3.744
7.	Distribution Primary	–	–	4.320	5.577	3.707
8.	Transmission	–	–	4.277	5.522	3.670

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-14	943,942	38,695,756	4.099	2,186,482	69,335,693	3.171	3,130,424	108,031,448	3.451
Feb-14	746,257	29,976,426	4.017	2,008,905	63,980,043	3.185	2,755,072	93,956,469	3.410
Mar-14	731,189	26,957,353	3.687	2,235,527	74,571,902	3.336	2,966,716	101,529,255	3.422
Apr-14	1,097,848	51,851,964	4.723	1,956,957	65,579,300	3.351	3,054,805	117,431,264	3.844
May-14	1,340,577	100,364,691	7.487	2,338,227	84,613,516	3.619	3,678,804	184,978,207	5.028
Jun-14	1,424,635	71,016,802	4.985	2,641,126	91,157,952	3.451	4,065,761	162,174,754	3.989
Jul-14	1,565,806	80,448,844	5.135	2,616,191	89,027,790	3.403	4,182,997	169,476,634	4.052
Aug-14	1,449,388	90,662,803	6.255	2,817,534	97,909,543	3.475	4,266,922	188,572,346	4.419
Sep-14	1,448,413	77,758,876	5.369	2,482,395	80,573,739	3.246	3,930,808	158,332,614	4.028
Oct-14	1,238,447	65,930,950	5.324	2,078,761	74,688,432	3.593	3,317,208	140,619,382	4.239
Nov-14	561,446	23,903,790	3.614	2,169,550	77,422,505	3.569	2,830,996	101,326,295	3.579
Dec-14	892,102	33,978,468	3.809	2,192,000	71,630,000	3.277	3,084,102	105,608,469	3.431
TOTAL	13,541,060	691,546,732	5.107	27,723,555	940,690,416	3.393	41,264,615	1,632,237,148	3.956

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST			
WEIGHTING MULTIPLIER	1.291	0.858	1.000

Duke Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2012
Estimated for the Period of : January through December 2014

		Energy Delivered @ Billing Level					Energy		
		Billed MWH	Unbilled MWH	Total MWH	% of Total	Delivery Efficiency	Required @ Source Level	% of Total	Jurisdictional Loss Multiplier
Retail									
Transmission		336,763	2,768	339,531		0.9844331	344,900		
Distribution Primary		3,994,133	32,827	4,026,960		0.9744331	4,132,619		
Distribution Secondary		32,050,561	263,420	32,313,981		0.9401722	34,370,280		
Total Retail		36,381,457	299,015	36,680,472	97.01%	0.9442098	38,847,799	97.15%	1.00150
						5.58%			
Wholesale									
Generation Level		753,841	(40,142)	713,699		1.0000000	713,699		
Transmission		395,998	(6,112)	389,886		0.9844331	396,051		
Distribution Primary		26,868	771	27,639		0.9744331	28,364		
Distribution Secondary		-	-	-			-		
Total Wholesale		1,176,707	(45,483)	1,131,224	2.99%	0.9939457	1,138,115	2.85%	0.95139
						0.61%			
Subtotal Class		37,558,164	253,532	37,811,696	100.00%	0.9456254	39,985,914	100.00%	1.00000
						5.44%			
Non-Class									
SEPA	Transmission	83,419	-	83,419		0.9844331	84,738		
Homestead - Base	Generation	197,004	1,802	198,806		1.0000000	198,806		
SECI - Base	Generation	84,165	(7,601)	76,564		1.0000000	76,564		
Homestead - Intermediate	Generation	-	-	-		1.0000000	-		
Reedy Creek - Base	Generation	43,313	396	43,709		1.0000000	43,709		
Seminole Elect. Coop	Generation	56,399	(5,093)	51,306		1.0000000	51,306		
Tallahassee - Base	Transmission	100,140	916	101,056		0.9844331	102,654		
Gainesville - Base	Generation	26,404	241	26,645		1.0000000	26,645		
Interchange	Generation	534,580	-	534,580		1.0000000	534,580		
Company Use	Secondary	149,355	-	149,355		0.9401722	158,859		
Total Non-Class		1,274,779	(9,339)	1,265,440			1,277,861		
Total System		38,832,943	244,193	39,077,136		0.947008	41,263,775		

EXHIBIT NO. 101

DOCKET NO: 130001-EI

WITNESS: Terry J. Keith

PARTY: FPL

DESCRIPTION: Revised E-10 Schedules reflecting Storm Charge effective January 1, 2014 per November 1, 2013 Storm Charge routine true-up filing and revised base rate amount effective January 1, 2014 and June 1, 2014 per October 4, 2013 EPU filing

DOCUMENTS: Schedule E-10 for the period January 2014 through June 2014, Schedule E-10 for the period June 2014 through December 2014 (including Riviera Beach Energy Center projected fuel savings), Schedule E-10 for the period January 2014 through December 2014 (traditional methodology)

PROFFERED BY: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 101
PARTY Florida Power & Light Company
DESCRIPTION Terry J. Keith - Revised E-10 Schedules reflecting Storm Charge effective 01/01/14

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	SEPT 13	PROPOSED [1] JAN 14 - MAY 14	DIFFERENCE $	DIFFERENCE %
BASE	$51.33	$52.47	$1.14	2.22%
FUEL	$26.33	$30.67	$4.34	16.48%
CONSERVATION	$2.33	$3.37	$1.04	44.64%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%
STORM RESTORATION SURCHARGE	$1.07	$0.84 [2]	-$0.23	-21.50%
SUBTOTAL	$92.73	$97.51	$4.78	5.15%
GROSS RECEIPTS TAX	$2.38	$2.50	$0.12	5.04%
TOTAL	**$95.11**	**$100.01**	$4.90	5.15%

Notes: [1] Base rate changes for January 2014 are based on estimated EPU increase per October 4, 2013 filing

[2] Storm Restoration Surcharge for January 2014 is based on November 1, 2013 true-up filing

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	SEPT 13	PROPOSED [1] JAN 14 - MAY 14	DIFFERENCE $	DIFFERENCE %	PROPOSED [1] JUN 14 - DEC 14	DIFFERENCE $	DIFFERENCE %
BASE	$51.33	$52.47	$1.14	2.22%	$54.86	$2.39	4.55%
FUEL	$26.33	$30.67	$4.34	16.48%	$29.47	-$1.20	-3.91%
CONSERVATION	$2.33	$3.37	$1.04	44.64%	$3.37	$0.00	0.00%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%	$7.86	$0.00	0.00%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%	$2.30	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.07	$0.84 [2]	-$0.23	-21.50%	$0.84 [2]	$0.00	0.00%
SUBTOTAL	$92.73	$97.51	$4.78	5.15%	$98.70	$1.19	1.22%
GROSS RECEIPTS TAX	$2.38	$2.50	$0.12	5.04%	$2.53	$0.03	1.20%
TOTAL	**$95.11**	**$100.01**	$4.90	5.15%	**$101.23**	$1.22	1.22%

Notes: [1] Base rate changes for January 2014 and June 2014 are based on estimated EPU increase per October 4, 2013 filing

[2] Storm Restoration Surcharge for January 2014 is based on November 1, 2013 true-up filing

COMPANY: FLORIDA POWER & LIGHT COMPANY

	SEPT 13	PROPOSED [1] JAN 14 - DEC 14	DIFFERENCE $	DIFFERENCE %
BASE	$51.33	$52.47	$1.14	2.22%
FUEL	$26.33	$29.92	$3.59	13.63%
CONSERVATION	$2.33	$3.37	$1.04	44.64%
CAPACITY PAYMENT	$9.38	$7.86	-$1.52	-16.20%
ENVIRONMENTAL	$2.29	$2.30	$0.01	0.44%
STORM RESTORATION SURCHARGE	$1.07	$0.84 [2]	-$0.23	-21.50%
SUBTOTAL	$92.73	$96.76	$4.03	4.35%
GROSS RECEIPTS TAX	$2.38	$2.48	$0.10	4.20%
TOTAL	**$95.11**	**$99.24**	$4.13	4.34%

Notes: [1] Base rate changes for January 2014 are based on estimated EPU increase per October 4, 2013 filing

[2] Storm Restoration Surcharge for January 2014 is based on November 1, 2013 true-up filing

EXHIBIT NO. 102

DOCKET NO: 130001-EI

WITNESS: Grissette

PARTY: FPL

DESCRIPTION: FPL's Fukushima "Fact Sheets"

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 130001-EI EXHIBIT 102
PARTY Office of Public Counsel
DESCRIPTION Don Grissette
FPL's Fukushima "Fact Sheets"

FPL

Fact Sheet

St. Lucie

The St. Lucie Nuclear Power Plant is designed with multiple, redundant safety systems.

Site Vice President
Joe Jensen

Site Communications Manager
Doug Andrews
6501 South Ocean Drive
Jensen Beach, FL 34957

Corporate Media Line
(305) 552-3888

Enhancing Nuclear Plant Safety after Fukushima

Since the devastating earthquake and tsunami in Japan, Florida Power & Light has taken a highly proactive approach to revalidating the safety of our nuclear plants. In addition, we have devoted significant time and focused attention to help make our facilities even safer.

Using scenarios more extreme than the Fukushima event, FPL has:

Revalidated plant safety:

Dedicated thousands of hours to revalidating safety systems: Since the Fukushima event St. Lucie members have spent thousands of hours performing additional safety inspections to revalidate the readiness of all critical systems, procedures, and emergency training programs.

Reconfirmed the health of emergency equipment: Immediately following the Japanese emergency, we re-examined our extensive emergency procedures and tested emergency response equipment put in place after 9-11 to verify St. Lucie could respond to extreme events.

Ensured the availability of emergency power: St. Lucie conducted detailed evaluations to ensure that emergency power for redundant safety systems is fully available in the case of a Fukushima-like emergency.

Confirmed the ability to withstand extreme natural events: The St. Lucie team reconfirmed the plant's ability to withstand severe natural events including earthquakes, flooding and fires.

Added additional layers of safety:

Enhanced core and spent fuel cooling capability: A St. Lucie specific strategy has been developed, procedures implemented and equipment purchased to ensure that core and spent fuel cooling could be maintained and the impact of extreme events like Fukushima could be effectively mitigated.

(Continued on next page)

High-pressure water cannons are tested as part of plant emergency readiness.

Invested nearly a million dollars in upgrades: We have invested nearly a million dollars to add additional layers of safety at St. Lucie. For example, we have ordered additional:

- » High-capacity pumps that run on diesel fuel (which is already safely stored on site) in order to provide additional backup cooling water for plant safety systems.
- » Diesel-powered generators capable of providing additional emergency power to monitoring, emergency lighting and communications systems.

Enhanced communication capabilities: St. Lucie is upgrading emergency communications equipment, including modernizing satellite phones, to ensure that communications can be maintained even if all power is lost for an extended period of time.

Updated operator training programs: FPL has included lessons-learned from the Fukushima event in all plant operator and emergency responder training programs.

Full-time event response team: To effectively oversee our company's response and integrate lessons learned from the Fukushima event into plant activities going forward, FPL continues to maintain a full-time nuclear Fleet response team. This team is responsible for implementing all policy changes in a uniform way across all of our nuclear plants.

Safety Confirmed by Independent Experts

"The Nuclear Regulatory Commission continues to determine that US nuclear plants are safe."

- NRC Frequently Asked Questions, February 2012

St. Lucie built-in safety features:

Built in a low-risk seismic zone: St. Lucie is located in the lowest hazard zone for earthquakes according to the U.S. Geological Survey.

- » **Constructed to withstand earthquakes:** The plant is designed to withstand earthquakes and other natural events stronger than ever recorded in the region.
- » **Protected from flooding:** The plant is elevated 20 feet above sea level to protect against flooding and extreme storm surges.

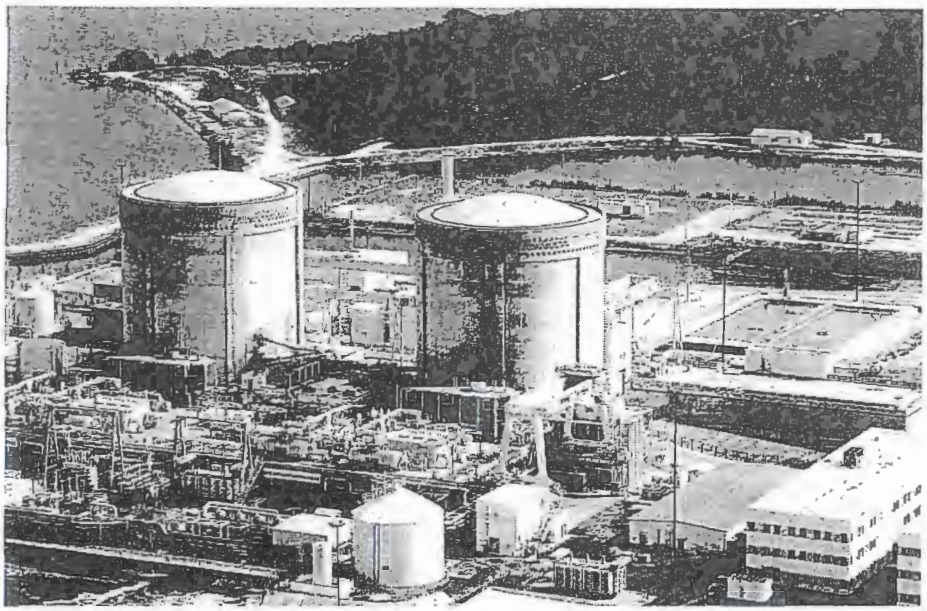
Designed with multiple safety systems: Redundant safety systems built into the plant design include:

- » Four diesel generators that are protected by a concrete and steel-reinforced building.
- » Additional reactor cooling system powered by steam generated by the plant itself.
- » Back-up batteries for critical safety systems are stored on-site.
- » External cooling options (i.e. injection and fire pumps) are pre-staged onsite; can use ocean water for cooling.
- » Seven-day power supply: Safety and cooling systems can be powered for seven days without requiring any offsite power or additional fuel.
- » Highly trained plant operators: For one full week out of every six weeks, plant operators must prove their ability to safely operate the plant in a variety of worst-case scenarios that include earthquakes, severe storms, flooding, loss-of-power, and loss of reactor core cooling.

FPL.

Fact Sheet

Turkey Point



The Turkey Point Nuclear Power Plant is designed with multiple, redundant safety systems.

Site Vice President
Mike Kiley

Site Communications Manager
Bianca Cruz : (305) 246-7204

9760 SW 344th Street
Florida City, FL 33035

Enhancing Nuclear Plant Safety after Fukushima

Since the devastating earthquake and tsunami in Japan, Florida Power & Light has taken a highly proactive approach to revalidating the safety of our nuclear plants. In addition, we have devoted significant time and focused attention to help make our facilities even safer.

Using scenarios more extreme than the Fukushima event, FPL has:

Revalidated plant safety:

Dedicated thousands of hours to revalidating safety systems: Since the Fukushima event Turkey Point members have spent thousands of hours performing additional safety inspections to revalidate the readiness of all critical systems, procedures and emergency training programs.

Reconfirmed the health of emergency equipment: Immediately following the Japanese emergency, we re-examined our extensive emergency procedures and tested emergency response equipment put in place after 9-11 to verify Turkey Point could respond to extreme events.

Ensured the availability of emergency power: Turkey Point conducted detailed evaluations to ensure that emergency power for redundant safety systems is fully available in the case of a Fukushima-like emergency.

Confirmed the ability to withstand extreme natural events: The Turkey Point team reconfirmed the plant's ability to withstand severe natural events including earthquakes, flooding and fires.

Added additional layers of safety:

Enhanced core and spent fuel cooling capability: A Turkey Point specific strategy has been developed, procedures implemented and equipment purchased to ensure that core and spent fuel cooling could be maintained and the impact of extreme events like Fukushima could be effectively mitigated.

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On March 11, 2011 at 2:45pm Japan Standard Time (JST) a 9.0 magnitude earthquake hit Japan. This earthquake caused a Tsunami to hit Japan. Due to the earthquake, 11 nuclear reactors in Japan went into "scram" or automatic shutdown.

There are significant differences between the affected Japanese reactors and FP&L's St. Lucie plant:

- The Japanese nuclear plants are a Boiled Water Reactor (BWR) designs. The St. Lucie plant is a Pressurized Water Reactor (PWR) design.

- PWR reactors have more redundancy on all safety systems and dual emergency generators for each reactor.

- PWR reactors have a separate steam-driven cooling pump system that can run the plant's cooling pumps without depending on offsite power or the diesel generator, BWR reactors do not.

- BWRs control rods are hydraulic driven and are inserted from the bottom of the reactor. PWR reactors control rods are held in place electro-magnetically and are inserted from the top. A loss of power would release the rods. The control rods end the fission process.

- The Japanese reactors are a much older design than the St. Lucie Plant and do not have the quantity of emergency core cooling water on hand.

- In a PWR the radioactive materials are contained in one location of the system where as a BWR the radioactive materials are located throughout the system.

- Another critical safety component in PWR reactors is the hydrogen recombiner. This system takes atmospheric hydrogen inside containment and converts it into water. The Japanese BWRs involved (1st generation GE design) do not.

- The explosions in the 2 Japanese units occurred during the venting of the secondary containments pressure. The explosions were not caused by a hydrogen bubble but the atmospheric hydrogen compounded the explosion.

- Given the difference in design and FP&L's robust high water emergency plan and the plants design to withstand earthquakes (even though there is little chance of seismic activity in St. Lucie County) a similar accident here is highly unlikely.

From FPL: FACT SHEET ON FLORIDA POWER & LIGHT NUCLEAR PLANTS

Florida Power & Light is closely monitoring the situation in Japan.

Since the earthquake and subsequent tsunami, FPL executives have been coordinating with the Nuclear Energy Institute, the Institute of Nuclear Power Operations and the World Association of Nuclear Operators with regard to the impact of these events on the operation of the Fukushima Daiichi nuclear plant in Japan.

- At this time, all of the facts are not fully known. This is further complicated by the fact that emergency response officials in Japan are dealing with the situation at the Fukushima Daiichi nuclear plant in addition to the overall tsunami recovery efforts.
- It is important to note that because of location, the seismic activity in Japan is of a greater magnitude than what could likely happen in Florida.

As compared to Fukushima Daiichi, Florida's reactors are of a newer design and have additional safety systems as a result.

- The World Association of Nuclear Operators reports that the Unit 1 TEPCO Daiichi unit is an older Boiling Water Reactor (Florida has Pressurized Water Reactors only). Relative to the Japanese plant, FPL's Florida nuclear plants have additional safety systems because of their more recent design.
- The issue in Japan deals with the complete loss of power to run decay heat removal pumps (the pumps that circulate water in order to cool the reactor core). Both of our Florida plants only require one diesel generator to fully supply the power required to meet core cooling needs. Each station has four diesel generators installed for redundancy (four at Turkey Point; Four at St. Lucie).
- In addition, unlike the Japanese plant, FPL plants have an additional, separate steam-driven cooling pump system. This steam-driven cooling system can run the plant's cooling pumps without depending on any offsite power or the diesel generators.
- In essence this means that the FPL plants at St. Lucie and Turkey Point have multiple redundancies relative to the Fukushima Daiichi facility.

St. Lucie and Turkey Point are designed for severe events that could impact our state.

- FPL's nuclear power plants at Turkey Point and St. Lucie are outside of known "high hazard" earthquake zones (as defined by United States Geological Society and the Nuclear Regulatory Commission).
- Each plant has been specially designed to withstand a variety of natural events such as earthquakes, storm surges and flooding associated with hurricanes, tornadoes and high winds without losing capability to perform their safety functions. Both are elevated to deal with the storm surge of a Category 5 hurricane (20 feet above sea level).
- Even though an event like the Japanese earthquake is unlikely, all FPL plants have had additional safety margin added to the "worst case" scenario to ensure the plants can withstand events beyond their licensing basis.

Our nuclear plants have extensive emergency plans and rigorous operator training programs.

- All nuclear power plants are designed for and have emergency operating procedures to address worst-case scenarios, including earthquakes, loss of core cooling, and loss of all onsite and offsite power.
- The procedures used in emergencies are part of plant operator training. Plant Operators are required to undergo knowledge and performance testing one week out of every six weeks. That training involves the use of real life responses on a plant simulator.
- For conditions warranting public evacuation, dedicated communications systems linking emergency operations centers are in place; public alert systems (sirens) are in place; and, local emergency facilities that are staffed by state and local government emergency response agencies would be fully manned.
- The plant emergency response is tested quarterly via emergency drills involving both onsite and offsite emergency response teams.
- Even though an event of this nature is unlikely in Florida, similar natural emergency conditions are routinely exercised by reactor operators and emergency response agencies in Florida.